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May 15, 2008

BY PERSONAL DELIVERY (10 COPIES) AND EMAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
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Toronto, Ontario M4P 1E4
Fax: (416) 440-7656
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Dear Ms. Walli:

Re: Pollution Probe – Supplemental Expert Evidence
EB-2007-0050 – Hydro One – Bruce-Milton Transmission Reinforcement Project

Please find enclosed supplemental evidence on behalf of Pollution Probe's experts.

Yours truly,

B. Alexander

Basil Alexander

BA/ba

Encl.

cc: Applicant and Intervenors per Procedural Order No. 8

Before the Ontario Energy Board

EB-2007-0050
Hydro One Networks Inc.

Leave To Construct A Transmission Reinforcement Project Between The Bruce Power Facility And Milton Switching Station, All In The Province Of Ontario (Bruce-Milton Transmission Reinforcement Project)

Supplemental Direct Evidence of

Robert M. Fagan, Synapse Energy Economics
and
Peter J. Lanzalotta, Lanzalotta Associates

Prepared on behalf of Pollution Probe

May 15, 2008

Q. Are you the same Mr. Fagan and Mr. Lanzalotta who filed direct evidence in this proceeding on behalf of Pollution Probe on April 18, 2008?

A. Yes.

Q. What is the purpose of this supplemental evidence?

A. The purpose of this supplemental evidence is twofold.

First, we provide an independent estimate of locked-in (or "undelivered") energy quantities (MWh per month and per year, 2012-2030) associated with a transmission alternative that includes near-term and "interim" measures including series compensation and generation rejection, but excludes the proposed Bruce to Milton line; and to provide the reasoning behind that estimate. The estimate is provided to further demonstrate that the benefits of the proposed Bruce to Milton line – i.e., avoiding these locked-in energy quantities (along with reducing system losses) – do not outweigh its cost. We do this by using Hydro One's estimates of average annual per unit value of locked-in energy and applying them to our estimates of locked-in energy quantities to show the benefits of the proposed line due to avoiding the locked-in energy. We also include Hydro One's estimates of the value associated with improving transmission losses. We show that the overall benefits remain lower than the costs of the proposed line.

Second, we critique Hydro One's use of the OPA financial evaluation model to determine locked-in energy estimates.

Q. Why was this not addressed in your direct evidence?

A. Our direct evidence was filed on April 18, 2008. As of that date, we had yet to receive certain information from Hydro One that we were anticipating would be forthcoming prior to the commencement of the hearing. That information would have allowed us to more fully comprehend the model used by Hydro One and the OPA to compute locked-in energy. Eventually we received fuller explanation of the model, including time and date data on transmission penalty values used in the model, the password to view the "visual basic" computer code in the model, and the explanations provided at the May 9, 2008 technical conference session at the Board. That allowed us to more properly consider Hydro One's use of the OPA financial evaluation model and form our own estimate of locked-in energy.

Q. How is this supplemental evidence structured?

A. In the first section of this supplemental evidence, we present a comparison of the annual locked-in energy estimates of Hydro One and Synapse for 2012-2030. Next we explain how we conducted our own analysis and produced estimates of monthly locked-in energy for the same time period as provided by Hydro One (i.e., for all months from January 2012 through December 2030). We then present the monthly-delineated estimates of locked-in energy quantities (MWh per month) provided by Hydro One, based on their response to Pollution Probe's discovery request number 47 c), provided by Hydro One as Exhibit C, Tab 2, Schedule 47, Attachment B on April 10, 2008 (non-confidential component) and April 15, 2008 (confidential component).

We then present our estimates of monthly locked-in energy quantities in tabular format. We compare our monthly estimates of locked-in energy quantities to Hydro One's estimates. We identify the variables that drive estimates of locked-in energy. In particular, we focus on the monthly variation in locked-in energy and the reasons behind that variation. Lastly, we discuss the effect of our estimates on the overall value of locked-in energy.

We also critique Hydro One's use of the OPA financial evaluation model to estimate locked-in energy. We review the three main elements underpinning the model – its representation of nuclear generation, wind generation and transmission capability. We describe the shortcomings present in each of those areas of the model. We note that we have had little time to carefully examine the model's underlying code since it was only provided after commencement of the hearings.

Q. Can you summarize your findings?

A. Yes. Synapse estimates that locked-in energy quantities over the 2012-2030 time period will be significantly less than Hydro One's estimates.

In the absence of Bruce B refurbishment, Synapse estimates total locked-in energy quantities (2012-2030) of approximately 3.2 million MWh, about 38% of the 8.5 million MWh estimated by Hydro One. Using Synapse's estimate, the overall level of benefit associated with "avoiding locked-in energy" if the proposed line is built is reduced from Hydro One's estimate of $374 million (NPV, $2007) to on the order of $141 million. Even when combined with transmission loss benefits, the total benefit of avoided locked-in energy and lower transmission losses is far below the cost of the proposed line. Synapse's estimate of the net benefit associated with building the proposed transmission line is negative $245 million (NPV, $2007). For comparison, Hydro One's estimate of total benefits of building the proposed line is $618 million, for a net benefit of negative $12 million.

If Bruce B is refurbished, Synapse estimates locked-in energy quantities of 7.4 million MWh, about 48 percent of the 15.5 million MWh estimated by Hydro One. With Bruce B refurbishment, Synapse estimates a net benefit associated with building the proposed line of negative $72 million. For comparison, Hydro One's estimate of net benefits is positive $219 million.

In summary, according to Synapse's estimates, if the Bruce B units are not refurbished, the proposed transmission line's net benefit is negative $245 million (NPV, $2007), that is, the costs of the proposed transmission line outweigh the benefits by about $245 million. If Bruce B is refurbished, Synapse estimates the transmission line as having a net benefit of negative $72 million.

These results are shown on Tables 1A and 1B, which follow this summary answer.

Hydro One use of the OPA financial evaluation model exaggerates the level of locked-in energy by 1) using a 2-state model of nuclear generation, 2) not properly accounting for the effect of spatial diversity of wind resources on aggregate output of the full 1700 MW of future wind in the Bruce area, and 3) by failing to consider monthly or seasonal differences when applying "penalty data" or derating the transmission system limits out of the Bruce area.

Table 1A. Benefits of Proposed Bruce to Milton Double Circuit 500 kV Line

Avoided Locked-in Energy and Losses Compared to Near-Term and "Interim" Measures (Series Compensation and Generation Rejection)

Without Refurbishment of Bruce B

	Hydro One Estimate Avoided Losses, LIE, BSPS Capital Cost						**Synapse Estimate Avoided Losses, LIE, BSPS Capital Cost**					
Year	Value of Avoided Losses NPV $2007 Million	LIE MWh (Scenario "D")	LIE Value Scenario "D" NPV $2007 Million	Estimated Value per MWh, NPV $2007 per MWh	Value of Avoided BSPS Capital Costs NPV $2007	Total Benefits NPV $2007 Million	Value of Avoided Losses NPV $2007 Million	LIE MWh	LIE Value NPV $2007 Million	Estimated Value per MWh, NPV $2007 per MWh	Value of Avoided BSPS Capital Costs NPV $2007	Total Benefits Losses + LIE + BSPS Capital Costs
2010					6	6					6	6
2011						0						
2012	17	6,497	0	-		17	17	-				17
2013	23	608,816	29	47.63		52	23	62,076				23
2014	22	1,115,368	52	46.62		74	22	398,142	19	46.62		41
2015	22	1,340,332	63	47.00		85	22	692,030	33	47.00		55
2016	21	1,340,332	60	44.77		81	21	694,190	31	44.77		52
2017	20	1,340,332	58	43.27		78	20	692,030	30	43.27		50
2018	20	1,340,332	55	41.03		75	20	692,030	28	41.03		48
2019	18	1,340,332	53	39.54		71	18	-				18
2020	13	102,656	4	38.97		17	13	-				13
2021	9	3,219	0	-		9	9	-				9
2022	7	-	0			7	7	-				7
2023	7	-	0			7	7	-				7
2024	6	-	0			6	6	-				6
2025	6	-	0			6	6	-				6
2026	6	-	0			6	6	-				6
2027	6	-	0			6	6	-				6
2028	5	-	0			5	5	-				5
2029	5	-	0			5	5	-				5
2030	5	-	0			5	5	-				5
Total	238	8,538,216	374		6	**618**	238	3,230,498	141		6	**385**
Cost of Proposed Line, NPV $2007 Million						**630**						**630**
Net Benefit, NPV $2007 Millions						**-11.78**						**-245.27**

Key Assumptions - Synapse Estimates of LIE

No. Units in Operation - Without Refurbishment of Bruce B

2012	2013-2018	2019	2020	2021	2022	2023	2024-2030
6-7	8	7	6	5	4	4	4

Summer/Winter Capacity Factor, Bruce Nuclear	95.0%
Shoulder Capacity Factor, Bruce Nuclear	70.0%
Average Annual Capacity Factor, Bruce Nuclear	86.7%
Wind Capacity Factor, Winter and Shoulder	40.0%
Wind Capacity Factor, Summer	20.0%
Average Annual Capacity Factor, Bruce Wind	33.3%
Transmission Limit MW	7,076
Derate MW - HONI Monthly Ave Pen Data	445-887

Sources: Hydro One Estimates of LIE, Losses, BSPS Capital Costs

Responses to:

PP7, PP9, PP10, PP11, PP47

Table 1B. Benefits of Proposed Bruce to Milton Double Circuit 500 kV Line

Avoided Locked-in Energy and Losses Compared to Near-Term and "Interim" Measures (Series Compensation and Generation Rejection)

With Refurbishment of Bruce B

	Hydro One Estimate Avoided Losses, LIE, BSPS Capital Cost						**Synapse Estimate Avoided Losses, LIE, BSPS Capital Cost**					
Year	Value of Avoided Losses NPV $2007 Million	LIE MWh (Scenario "D")	LIE Value Scenario "D" NPV $2007 Million	Estimated Value per MWh, NPV $2007 per MWh	Value of Avoided BSPS Capital Costs NPV $2007	Total Benefits NPV $2007 Million	Value of Avoided Losses NPV $2007 Million	LIE MWh	LIE Value NPV $2007 Million	Estimated Value per MWh, NPV $2007 per MWh	Value of Avoided BSPS Capital Costs NPV $2007	Total Benefits Losses + LIE + BSPS Capital Costs
2010					6	6					6	6
2011												
2012	20	6,497	0			20	20	-				20
2013	23	608,816	29			52	23	62,076				23
2014	21	1,115,368	52	46.62		73	21	398,142	19	46.62		40
2015	21	1,340,332	63	47.00		84	21	692,030	33	47.00		54
2016	20	1,340,332	60	44.77		80	20	694,190	31	44.77		51
2017	19	1,340,332	58	43.27		77	19	692,030	30	43.27		49
2018	20	175,496	7	39.89		27	20	-	-			20
2019	15	4,676	0			15	15	-	-			15
2020	14	4,676	0			14	14	-	-			14
2021	13	4,676	0			13	13	-	-			13
2022	13	4,676	0			13	13	-	-			13
2023	17	175,496	6	34.19		23	17	-	-			17
2024	14	1,340,332	43	32.08		57	14	694,190	22	32.08		36
2025	13	1,340,332	41	30.59		54	13	692,030	21	30.59		34
2026	13	1,340,332	39	29.10		52	13	692,030	20	29.10		33
2027	12	1,340,332	38	28.35		50	12	692,030	20	28.35		32
2028	12	1,340,332	36	26.86		48	12	694,190	19	26.86		31
2029	11	1,340,332	35	26.11		46	11	692,030	18	26.11		29
2030	11	1,340,332	34	25.37		45	11	692,030	18	25.37		29
Total	302	15,503,697	541			**849**	302	7,386,998	250			**558**
Cost of Proposed Line, NPV $2007 Million						**630**						**630**
Net Benefit, NPV $2007 Millions						**219.22**						**-72.20**

No. of units in operation - With Refurbishment of Bruce B

2012	2013-2017	2018	2019-2022	2023	2024-2030
6-7	8	7	6	7	8

Summer/Winter Capacity Factor, Bruce Nuclear	95.0%
Shoulder Capacity Factor, Bruce Nuclear	70.0%
Average Annual Capacity Factor, Bruce Nuclear	86.7%
Wind Capacity Factor, Winter and Shoulder	40.0%
Wind Capacity Factor, Summer	20.0%
Average Annual Capacity Factor, Bruce Wind	33.3%
Transmission Limit MW	7,076
Derate MW - HONI Monthly Ave Pen Data	445-887

Sources: Hydro One Estimates of LIE, Losses, BSPS Capital Costs

Responses to:

PP7, PP9, PP10, PP11, PP47

Synapse Estimate of Locked-In Energy

Q. How did Synapse the estimates shown in Table 1A and 1B?

A. Synapse computed these amounts by estimating the locked-in energy in the Bruce area for each month from 2012-2030. The locked-in energy amount was computed to be equal to the difference between total generation capacity and available transmission capacity, if that difference was greater than zero (i.e., if generation capacity was greater than transmission capacity) multiplied by the number of hours in the month.

The total generation capacity in each month is equal to the sum of two components for each month: nuclear capacity and wind capacity.

Q. How was nuclear capacity determined?

A. Nuclear capacity is determined using three parameters: 1) OPA's planning values for maximum continuous rating (MCR), which are 850 MW for each Bruce B unit and 750 MW for each Bruce A unit; 2) Hydro One/OPA's schedule for the number of units available at Bruce; and 3) estimates of summer, winter and shoulder period capacity factor of the total of units available at Bruce for each respective month.

For the purposes of estimating locked-in energy, Synapse assumed an average annual capacity factor of 86.7% for the entirety of the Bruce station (6,400 MW with 8 units available); and proportionately lower when 7, 6, 5 or 4 units are available. This annual availability was composed of winter and summer month availability of 95%, and shoulder period availability of 70%, based on Hydro One/OPA's statement that planned outages will be during shoulder months. These monthly parameters average to 86.7% annually. This means that for winter and summer months when 8 units are available at Bruce, we assumed a total available output of 6,080 MW (= 6,400 x .95).

Q. What is the basis for using these values for winter, summer and shoulder capacity factor?

A. This assumption is based on two precepts. First, the pattern of historical Bruce nuclear station output during periods of availability of eight units (1987 – 1995) shows monthly averages never exceeded 90%, and in general were in the roughly 50% to 80% range, as shown in our direct evidence in Figure 8. Second, the effect of forced outages, overlap of planned outages into portions of the summer and winter periods, and the general uncertainty associated with predicting the extent to which all eight units will simultaneously be running at full MCR. These considerations led us to use a value of 95% for winter and summer; the shoulder period capacity factors were estimated to maintain an average annual capacity factor of 86.7%.

Q. How was the wind capacity determined?

A. Wind capacity is determined using 2 parameters: 1) Hydro One/OPA's schedule of installed wind capacity in the Bruce area (which ramps up to 1,700 MW total by 2015); and 2) assumed capacity factors of 40% in the winter and 20% in the summer. These assumptions imply a total annual capacity factor of 33.3%.

Q. What is the basis for using these values for winter and summer capacity factor?

A. The basis for these values is recognition that the wind resource is particularly stronger in the winter than in the summer, and that with 1,700 MW of wind a significant spatial diversity will exist that will serve to buffer the effect of peak output at any one turbine or wind farm, and contribute towards a flatter profile of overall wind resource output at any given time relative to the output profile of a single turbine or a single wind farm. The AWS Truewind report[1] states the following:

> "However, in both seasons, the value of wind during the peak hours of the day is generally consistent with the overall average winter and summer capacity values of 40% and 20% respectively". (page 4.6)

This quote is given in the context of a system-wide wind resource of 10,000 MW in the year 2020.

Q. What is the available transmission capacity?

A. Synapse used the 7,076 MW limit associated with "near term measures and SCAP" for the "elements out of service (use GR)" circumstance presented in Table 3 of Hydro One's Exhibit C, Tab 2, Schedule 47, Attachment A. Synapse then derated this limit in each month by the average monthly penalty based on data received subsequent to the May 9, 2008 technical conference. Those derating values are shown below:

Bruce Transmission System Penalty Data - MW - Monthly Averages

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan-Dec
2005	477	343	761	542	822	668	401	498	571	601	657	434	566
2006	488	496	451	850	821	967	568	761	856	680	1046	613	716
2007	372	379	809	796	735	622	367	226	596	985	959	655	626
All years average	446	406	673	729	793	752	445	495	674	756	887	567	636

Source: Hydro One data in response to undertaking of May 9, 2009. Data provided by Mr. Falvo.

<u>Hydro One Estimates of Monthly Locked-in Energy Quantities</u>

Q. What are Hydro One's estimates for monthly levels of locked-in energy?

A. The three tables below (tables 2 through 4, with confidential data blacked out) present Hydro One's estimates for three scenarios based on discovery request number 7 made by Pollution Probe. Those scenarios include: "C", "D" and "E", all of which include the series compensation measures. Scenario C assumes Bruce B is refurbished. Scenario D assumes Bruce B is not refurbished. Scenario E assumes Bruce B is not refurbished and that the capacity factor at Bruce nuclear station is 10% lower than OPA's estimate.

Q. What do these data show?

A. The data show two clear patterns that reflect 1) little or no locked-in energy in the months and years after Bruce B is retired; 2) reduced levels of locked-in energy in the shoulder months and the summer months relative to winter months for any given year. These rough patterns are to be expected given the stated assumptions about Bruce station availability (greater during winter and summer) and presumably given the difference in wind generation output between summer and winter months.

[1] Final Report to Ontario Power Authority (OPA), Independent Electric System Operator (IESO), Canadian Wind Energy Association (CanWEA) for Ontario Wind Integration Study. GE Energy Project Team and Michael Brower, AWS Truewind. October 6, 2006. Attached as Appendix A to this supplemental testimony.

Table 2. Hydro One Estimate of Monthly Locked-In Energy (MWh), Scenario "C", with Near-Term and "Interim" Measures With Bruce B Refurbishment

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
2012	[redacted]												6,498
2013													608,818
2014	169,899	169,899	169,899	12,140	12,140	96,803	96,803	96,803	96,803	12,140	12,140	169,899	1,115,368
2015	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2016	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2017	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2018	33,733	33,733	33,733	883	883	9,258	9,258	9,258	9,258	883	883	33,733	175,496
2019	1,073	1,073	1,073	-	-	96	96	96	96	-	-	1,073	4,676
2020	1,073	1,073	1,073	-	-	96	96	96	96	-	-	1,073	4,676
2021	1,073	1,073	1,073	-	-	96	96	96	96	-	-	1,073	4,676
2022	1,073	1,073	1,073	-	-	96	96	96	96	-	-	1,073	4,676
2023	33,733	33,733	33,733	883	883	9,258	9,258	9,258	9,258	883	883	33,733	175,496
2024	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2025	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2026	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2027	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2028	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2029	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2030	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
													15,503,700

Table 3. Hydro One Estimate of Monthly Locked-In Energy (MWh), Scenario "D", with Near-Term and "Interim" Measures No Bruce B Refurbishment

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
2012	[redacted]												6,498
2013													608,818
2014	169,899	169,899	169,899	12,140	12,140	96,803	96,803	96,803	96,803	12,140	12,140	169,899	1,115,368
2015	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2016	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2017	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2018	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2019	203,198	203,198	203,198	19,127	19,127	112,758	112,758	112,758	112,758	19,127	19,127	203,198	1,340,332
2020	33,733	33,733	33,733	-	-	96	96	96	96	-	-	1,073	102,656
2021	1,073	1,073	1,073	-	-	-	-	-	-	-	-	-	3,219
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
													8,538,219

Table 4. Hydro One Estimate of Monthly Locked-In Energy (MWh), Scenario "E", with Near-Term and "Interim" Measures No Bruce B Refurbishment, and Average Annual Capacity Factor of Bruce Nuclear Station 10% Lower than OPA's Estimate

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
2012	[redacted]												4,498
2013													255,129
2014	77,929	77,929	77,929	4,305	4,305	41,597	41,597	41,597	41,597	4,305	4,305	77,929	495,324
2015	96,848	96,848	96,848	7,081	7,081	49,615	49,615	49,615	49,615	7,081	7,081	96,848	614,176
2016	96,848	96,848	96,848	7,081	7,081	49,615	49,615	49,615	49,615	7,081	7,081	96,848	614,176
2017	96,848	96,848	96,848	7,081	7,081	49,615	49,615	49,615	49,615	7,081	7,081	96,848	614,176
2018	96,848	96,848	96,848	7,081	7,081	49,615	49,615	49,615	49,615	7,081	7,081	96,848	614,176
2019	96,848	96,848	96,848	7,081	7,081	49,615	49,615	49,615	49,615	7,081	7,081	96,848	614,176
2020	15,907	15,907	15,907	-	-	48	48	48	48	-	-	537	48,450
2021	537	537	537	-	-	-	-	-	-	-	-	-	1,611
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
													3,875,892

Source, All Tables: Exhibit C, Tb 2, Schedule 47, Attachment B

Q. What are Synapse's results for monthly locked-in energy estimates?

A. The tables below show our results.

Table 5. Synapse Estimate of Monthly Locked-In Energy (MWh)
No Bruce B Refurbishment

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	62,076	-	-	-	-	-	-	-	-	-	62,076
2014	32,480	2,677	201,948	-	-	38,301	-	-	-	-	-	122,735	398,142
2015	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2016	96,464	62,629	265,932	-	-	69,261	-	-	13,184	-	-	186,719	694,190
2017	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2018	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2019	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
													3,230,498

Table 6. Synapse Estimate of Monthly Locked-In Energy (MWh)
With Bruce B Refurbishment

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	62,076	-	-	-	-	-	-	-	-	-	62,076
2014	32,480	2,677	201,948	-	-	38,301	-	-	-	-	-	122,735	398,142
2015	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2016	96,464	62,629	265,932	-	-	69,261	-	-	13,184	-	-	186,719	694,190
2017	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2018	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	96,464	62,629	265,932	-	-	69,261	-	-	13,184	-	-	186,719	694,190
2025	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2026	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2027	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2028	96,464	62,629	265,932	-	-	69,261	-	-	13,184	-	-	186,719	694,190
2029	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
2030	96,464	60,469	265,932	-	-	69,261	-	-	13,184	-	-	186,719	692,030
													7,386,998

Key Assumptions

No. Units in Operation - Without Refurbishment of Bruce B

2012	2013-2018	2019	2020	2021	2022	2023	2024-2030
6-7	8	7	6	5	4	4	4

No. of units in operation - With Refurbishment of Bruce B

2012	2013-2017	2018	2019-2022	2023	2024-2030
6-7	8	7	6	7	8

Summer/Winter Capacity Factor, Bruce Nuclear	95.0%	
Shoulder Capacity Factor, Bruce Nuclear	70.0%	
Average Annual Capacity Factor, Bruce Nuclear	86.7%	
Wind Capacity Factor, Winter and Shoulder	40.0%	
Wind Capacity Factor, Summer	20.0%	
Average Annual Capacity Factor, Bruce Wind	33.3%	
Transmission Limit	7076	MW

Derate Pattern: Average values by Month from Hydro One Penalty Data, MW:

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
446	406	673	729	793	752	445	495	674	756	887	567

Q. What do these data show?

A. These results illustrate first that the effect of the lower summer capacity factors exhibited by wind resources in combination with the transmission penalty results in no locked-in energy during the summer months of July and August, and some locked-in energy in June and September; and that the effect of lower shoulder period capacity factors at the Bruce nuclear station leads to no locked-in energy in those months. The rest of the locked-in energy is in winter months. The effect of the transmission derate pattern is discernable, as June and September values are significantly higher than July and August values.

Q. How do these results contrast with Hydro One's results?

A. There are a number of differences we identify when comparing the results:

1. Our aggregate values are lower, but it is difficult to trace the exact source without more careful review of the full model provided by Hydro One during the hearing process. We assume that the interaction of the three elements of the OPA model – wind and nuclear generation and transmission limit levels – combine to exaggerate the locked-in energy effect.
2. Synapse estimates of locked-in energy during summer is about 12% of the total annual locked-in energy, while Hydro One's estimates include fully one-third of annual locked-in energy during these months.
3. Shoulder period estimates of lower Bruce nuclear capacity factor drive Synapse's estimate of zero locked-in energy during these periods.
4. Synapse assumed a Bruce retirement schedule that differs from the assumption made by Hydro One. Hydro One shows locked-in energy through 2019 as if all four of the Bruce B units remain on-line through this year. Synapse assumed that all four units would only be available through 2018.

Critique of Hydro Use of the OPA Financial Evaluation Model

Q. How does Hydro One's use of the OPA financial evaluation model exaggerate the level of locked-in energy estimated?

A. Hydro One use of the OPA financial evaluation model exaggerates the level of locked-in energy in the following way:

1. Hydro One uses a "2-state" model (either on or off) of nuclear generation that does not properly represent the real-world conditions of "partial" outages at units of the Bruce nuclear station. When units at Bruce are out of service, they are not necessarily fully offline, or operating at zero output; but rather may be derated and operating at less than 100%.[2] The model does not represent this real-world outage circumstance; it instead has a unit fully on or fully off any time a forced outage or planned outage is represented in the model. By simplifying the model in this manner, they create a probability distribution of aggregate Bruce nuclear station generation output that is weighted too

[2] For example, as stated by Mr. Chow, Technical Conference, May 9, 2008.

much towards the extremes of the distribution. This results in more locked-in energy than would occur in the real world because the model assumes too high an aggregate output at Bruce nuclear station during times when units are actually “online” but operating at less than 100% of their MCR.

2. Hydro One has not properly accounted for the effect of spatial diversity of wind energy in its representation of wind in the “wind buckets” portion of the financial evaluation model. This results in Hydro One estimating too high a coincident level of wind generation available to use the transmission system. Rather than estimate the effect of spatial diversity when up to 1700 MW of wind is on the system, Hydro One used data based on the wind regime at too few sites to properly represent geographic variation (or spatial diversity). This effect is seen in the way in which individual wind turbines’ and wind farms’ output is electrically aggregated and “shows up” on the grid as an instantaneous aggregation of generation. Hydro One did not further explore comments in the AWS Truewind report (attached as Appendix A to this supplemental testimony) that indicated that the wind data used by Hydro One was lacking in proper representation of spatial diversity.[3] Furthermore, they also did not address the additional spatial diversity effect that arises when increasing the total installed capacity in the Bruce area to 1,700 MW.

3. Hydro One used a randomly selected “penalty” associated with the transmission rating for flow away from the Bruce area. It based this penalty on the actual penalty experienced by the system over the years 2005-2007, however they did not attempt to apply the data in a way that respected variation in penalty levels across seasons or months. Exploration of the data revealed higher penalties during “shoulder” periods, and lower penalties during winter and summer seasons. If such trends were considered and used in the model, the result would have been lower levels of locked-in energy.

Q. Does this conclude your supplemental evidence?

A. Yes.

[3] See the AWS Truewind report at pages 3.5 – 3.6.

Appendix A   AWS Truewind Report

Final Report to:

Ontario Power Authority (OPA)

Independent Electricity System Operator (IESO)

Canadian Wind Energy Association (CanWEA)

for

Ontario Wind Integration Study

GE Energy Project Team:

Devin Van Zandt
Lavelle Freeman
Gao Zhi
Richard Piwko
Gary Jordan
Nicholas Miller

Michael Brower (AWS Truewind)

October 6, 2006

Foreword

This document was prepared by General Electric International, Inc. It is submitted to OPA, IESO, and CanWEA. Technical and commercial questions and any correspondence concerning this document should be referred to:

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Table of Contents

1 Executive Summary

The Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO), and the Canadian Wind Energy Association (CanWEA) (jointly called the "Requesting Parties") commissioned this wind integration study to aid in the development of the 20-year strategic Integrated Power System Plan (IPSP) for the province of Ontario. The strategic plan is intended to set the direction Ontario will take with regard to the mix of generation resources, demand response resources, and future transmission infrastructure needs. Renewable resources, such as wind generation, are likely to represent a more significant portion of the installed generation capacity in the future. This study examines the impact of moderate to significant penetration levels of wind generation on the operation of the Ontario bulk power system.

The results from this study are based upon the scenarios developed in concert with the Requesting Parties. The scenarios, shown in Table 1.1, represent the potential future development of wind projects within Ontario.

Table 1.1 Study Scenarios

Scenario Number	Description	Nameplate as a % of Peak Hourly Load	% of Total Yearly Energy
1	2009 Load plus 1,310MW of planned/existing nameplate wind capacity	4%	2%
2	2020 Load plus 5,000MW of nameplate wind capacity	17%	7%
3	2020 Load plus 6,000MW of nameplate wind capacity	20%	8%
4	2020 Load plus 8,000MW of nameplate wind capacity	27%	11%
5	2020 Load plus 10,000MW of nameplate wind capacity	33%	13%

A wide range of wind levels have been selected to help identify the incremental impact of wind on the Ontario power system. For each scenario, the incremental impact on generation scheduling and ramping, load following, regulation, and operating reserve requirements are assessed to maintain existing performance levels. In addition, the capacity value is determined for all scenarios. The results are summarized within this executive summary and described in detail in the following chapters.

1.1 Key Study Findings

Below is a list of the key findings from the study results. The details of how these findings were derived can be found in subsequent chapters of this report.

- The average capacity value of the wind resource in Ontario during the summer (peak load) months is approximately 17%. The capacity value ranges from 38% to 42% during the winter months (November to February) and from 16% to 19% during the summer months (June to August). Since 87% of the hits (periods within 10% of the load peak) occur during the summer months, the overall yearly capacity value is expected to be heavily weighted toward the summer. The overall yearly capacity value is approximately 20% for all wind penetration scenarios. In other words, 10,000 MW of installed nameplate wind capacity is equivalent to approximately 2,000 MW of firm generation capacity. The capacity value is generally insensitive to the wind penetration level, mainly due to good wind geographic diversity and the fact that the various wind output levels are derived by scaling the same wind groups. Further explanation of capacity value results can be found in Chapter 4.
- The results of the regulation analysis show that, in all scenarios, the incremental regulation needed to maintain current operational performance is small. With incremental regulation requirement defined as the increase in 3σ of the net-load with and without wind, the increase in regulation is only 11% with 10,000 MW of wind and 4% with 5,000 MW. This additional regulation could be handled within the current system operation framework. More detailed analysis and results can be found in Section 5.5.3.3.
- Incremental load following requirements are more substantial due to increased variability in the 5-minute timeframe. The year 2009 load with 1,310 MW of wind scenario could be easily accommodated with the existing generators. The year 2020 load with 5,000 MW of wind scenario shows a 17% increase in load following requirements. It is likely that online generators could provide this incremental requirement. Beyond 5,000 MW of wind, the additional load following requirement may exceed the capability of existing generators. It is important that any future supply mix strategy recognize that wind generators will likely displace more flexible generation resources and the remaining balance-of-portfolio resources must be able to accommodate this additional variability. See Section 5.5.2.3 for more details.
- The 10-minute operating reserve requirement is specifically tied to a single contingency, meaning that the reserve is meant to accommodate loss of a single unit, but not a simultaneous drop in generation *and* increase in load. Therefore, the 10-minute wind-alone variability was analyzed as a proxy for operating reserve requirements. The results show that with 5,000 MW of wind, the incremental operating reserve requirement is considered negligible but at higher wind penetrations, the incremental operating reserve requirement becomes more significant. The current largest contingency exposure on the Ontario bulk power system is 900 MW. For the 6,000 MW and 8,000 MW wind

penetration cases, the wind output dropped by more than 900 MW in ten minutes 4 times. With 10,000 MW of wind, the wind output dropped by more than 900 MW 10 times. The results indicate that an increase operating reserve requirement can be expected in order to accommodate extreme drops in wind generation for the high wind penetration scenarios. See Section 5.4.4 for more detailed results.

- For several of the scenarios, the minimum net-load point (with wind) is significantly reduced as compared to the minimum load-alone point. This has serious implications for the online generation resources during the low load periods and may require curtailment of wind power output or other mitigation measures. For the 10,000 MW scenario, wind energy output below the minimum load point represents 25% of the yearly energy. This is a significant proportion of the yearly energy output. If the minimum load-wind point drops far enough down into the generation stack, then only less maneuverable generation units may be left to serve the load. A complicating factor is that, during these low load-wind periods, the variability of the load-wind deltas is greater than the load-alone deltas. In other words, the maneuverability burden on the units serving the load during these periods is greater. These issues are further discussed in Sections 1.2.4 and 1.2.5.

- For all wind scenarios, the increase in hourly and multi-hourly variability, as measured by σ, due to wind is relatively small (not more than 10% for any scenario). From an hourly scheduling point of view, even 10,000 MW of wind would not push the envelope much further beyond the current operating point. However, the amount and magnitudes of *extreme* one-hour and multi-hour net-load changes are significantly greater with high wind penetration. With the addition of 10,000 MW of wind, the maximum one-hour net-load rise increases by 34%, and the maximum one-hour net-load drop increases by 30%. This data indicates that with large amounts of wind, much more one-hour ramping capability is needed for secure operation. Clearly the longest sustained ramping (up and down) occurs during the summer morning load rise and evening load decline periods. During these periods, (and others) the units may need to ramp continually over three or more hours. For the year 2020 load with 10,000 MW of wind scenario, the maximum positive three-hour load-wind delta increases by 17% and the maximum negative three-hour delta increases by 33%. The detailed results in Section 5.3.8 clearly illustrate the fact that units will have to undergo sustained three-hour ramping more often, and ramp further with the addition of large amounts of wind.

- The analysis shows that sudden (less than 10-minute) province-wide interruptions of wind generation power output are extremely unlikely and do not represent a credible planning contingency. When sudden changes in wind output do occur, the study shows that the spatial diversity of wind sites and wind groups would tend to limit the impact of individual site or group changes on the aggregate wind output. This includes the impact of extreme weather incidents such as windstorms and ice storms, which are two of the major concerns for wind tower structural integrity. However, windstorms in the form of hurricanes or tornadoes, and ice storms that are capable of severely damaging or toppling a wind structure move at finite speeds and are not capable of "*sudden*" wholesale damage to structures across Ontario within "ten minutes or less". Detailed analysis of extreme weather impacts can be found in Section 5.6 of this study.

1.2 General Observations and Recommendations

Clearly there is a potentially significant role for wind power in the future supply mix for the province of Ontario. The transmission and generation planning taking place today will largely determine the extent of this role. This study highlights areas of concern based upon the statistical behavior of load and wind. Effectively dealing with the highlighted issues will be challenging and involve a province-wide effort with key stakeholders. Below is a list of general observations and recommendations that are based upon our industry experience and the results of this and other wind integration studies we have completed. It is hoped that these recommendations will help the province of Ontario achieve its planning goals for wind generation.

1.2.1 Data collection at wind plants

One of most frustrating problems with evaluating the impact of wind generation on interconnected power grids is lack of adequate historical data from existing facilities. The problem is the same all across North America – wind generation facilities have been operating for several years, but historical records of wind generation output are either non-existent or are considered proprietary competitive information. Based on experience and data issues with this project and others, it is therefore recommended that:

a. The Ontario IESO continue, and where necessary improve, its process to record and store power output data from all operating wind plants on a continuing basis. The acquisition of site related meteorological data would be a valuable addition to the power output data.

b. New wind plants continue to be required to provide power output signals to the IESO as part of their interconnection agreements, and that the signals and communication channels shall be adequately maintained to achieve high availability (i.e., avoid gaps in data due to data acquisition or communication failures).

Access to such historical data will enable the IESO to continually improve its understanding of the impact of wind plants on grid operation, and to better predict the impacts of higher penetrations of wind generation in the future. This data will also serve as a basis to improve wind forecasting capability.

1.2.2 Wind Plant Control Features

As the results of this study demonstrate, increasing penetration of wind generation in a control area creates additional operational challenges. Consequently, advanced control features on wind plants (voltage regulation, low voltage ride through, curtailment, frequency regulation, etc.) become increasingly important to maintaining balanced, stable and secure operation of the power grid. Even though some of these control features may not be necessary to achieve adequate grid performance in the near term, they will be critical in the future. Therefore, it is very important that all new wind facilities be required to include these features now, so that they will be equipped to perform the required functions when the grid needs them. Installing wind plants with "plain vanilla" control features now with the expectation of retrofitting advanced controls later is impractical. Some types of wind generation equipment may not be upgradeable in the future, and grid performance will ultimately suffer as a consequence. It is necessary to start installing wind generation equipment now with the control features that will be needed to maintain adequate grid performance in the future.

1.2.3 Load Following Market

Increased penetration of wind generation will inherently require more balance of generation maneuverability to handle the potential increase in net variability from wind plant output. Based on results from this study and other similar studies of other control areas, large penetration levels of wind power is expected to significantly increase the requirement for load following in the Ontario control area. There is concern that as wind penetration increases, the presently available load-following capability will be depleted and operating flexibility will be degraded.

The IESO and OPA, each in their respective processes, have authority to require certain operational characteristics from generation, both existing and new. However, to achieve the amounts of load following required in the future may require economic incentives which do not exist today. In other markets this has been achieved through development of appropriate ancillary service markets. The IESO should pursue technical studies to define the load following requirements of the Ontario system; from these studies OPA and IESO could consider all available alternatives to preserve and expand the load following capability of generation in Ontario.

1.2.4 Low Load Period Considerations and Mitigation Measures

The majority of this study focuses on the impact of increased variability on the overall system performance. Although the variability is extremely important in assessing the incremental operational requirements, an equally important issue is low load period considerations.

There are often times throughout the year where the load is near its minimum and the wind production is quite high (such as early morning during a shoulder month). During such periods, the net load-wind level during the period could be up to 50% *lower* than the load-alone minimum point. In other words, the wind pushes the minimum load point lower than it ordinarily would be. This is illustrated in Figure 1.1 below which shows the load duration curves for year 2020 load-alone, and for the net-load (load-wind) in each year 2020 wind penetration scenario. The minimum load point (13,953 MW) is represented by the heavy horizontal line. The figure shows that there are a number of hours during the year when load-wind drops below 13,953 MW. Figure 1.2 is an enlargement of the area around the minimum load point which shows the number of hours that net-load (for each scenario) dips below 13,953 MW, as well as the percent of wind energy below the minimum load line. For 10,000 MW of wind the net-load drops to less than 7000 MW, which is 50% less than the minimum load point for load-alone (13,953 MW).

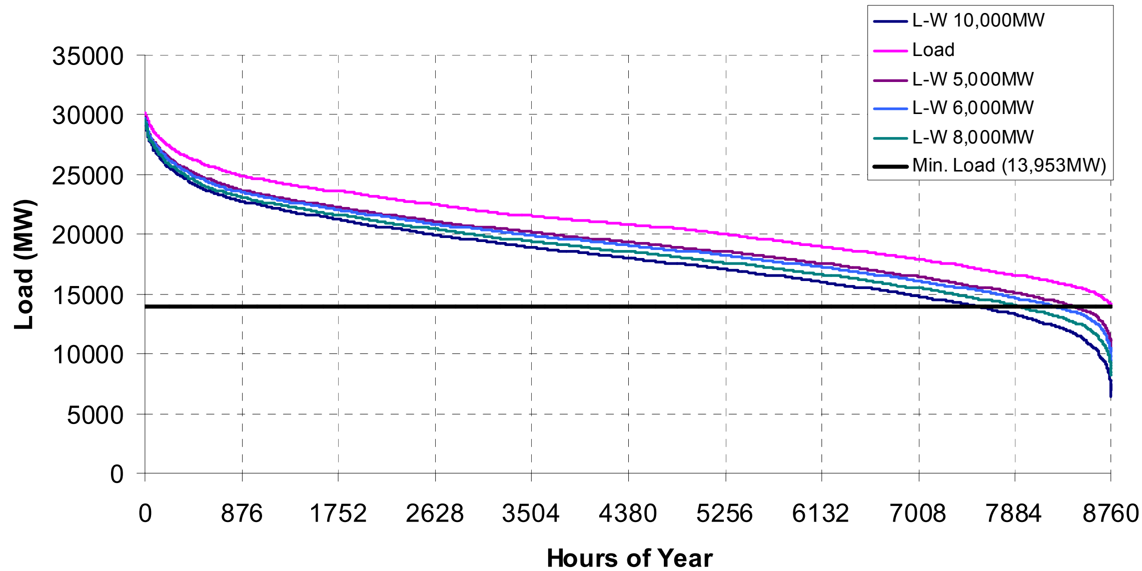

Figure 1.1 Duration Curves for year 2020 Load and Various wind Penetration Scenarios

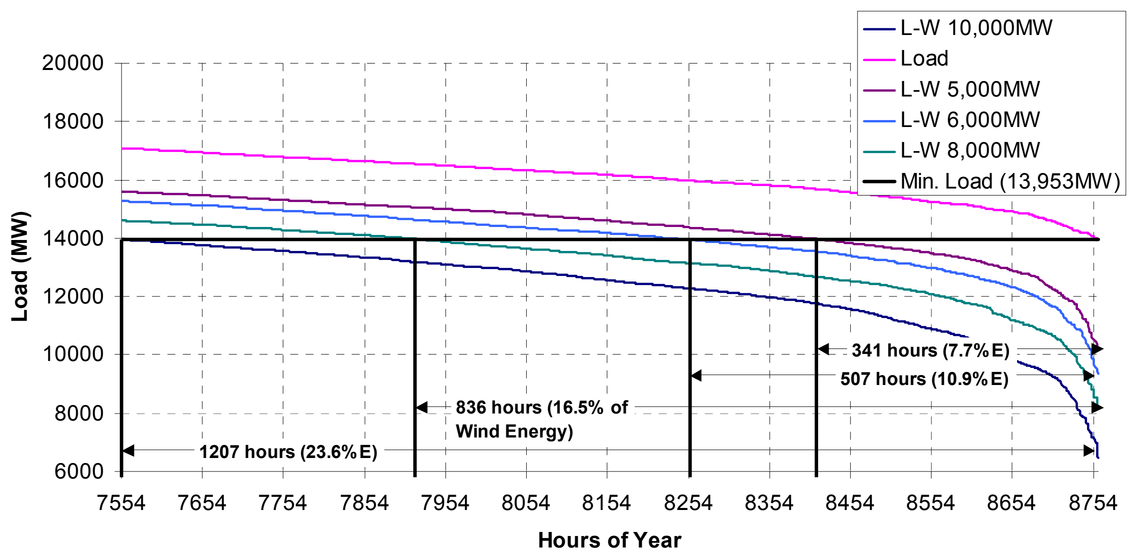

Figure 1.2 Magnification of Yearly Low Load Period for Load-Wind Duration

If the supply mix during these low load periods does not have adequate ramping capability to adjust for the wind variability, the secure, stable operation of the power system could be compromised.

Three points (low-load hour, median-load hour, and peak-load hour) were extracted from the duration curves for the load-alone and load with 10,000 MW of wind, and plotted in Figure 1.3. The impact of the wind seems insignificant at the peak-load hour (1), marginal at the median-load hour (4380) and quite significant at the low-load hour (8760). As shown in Figure 1.2, the load-wind is less than half the load-alone level at the low-load hour.

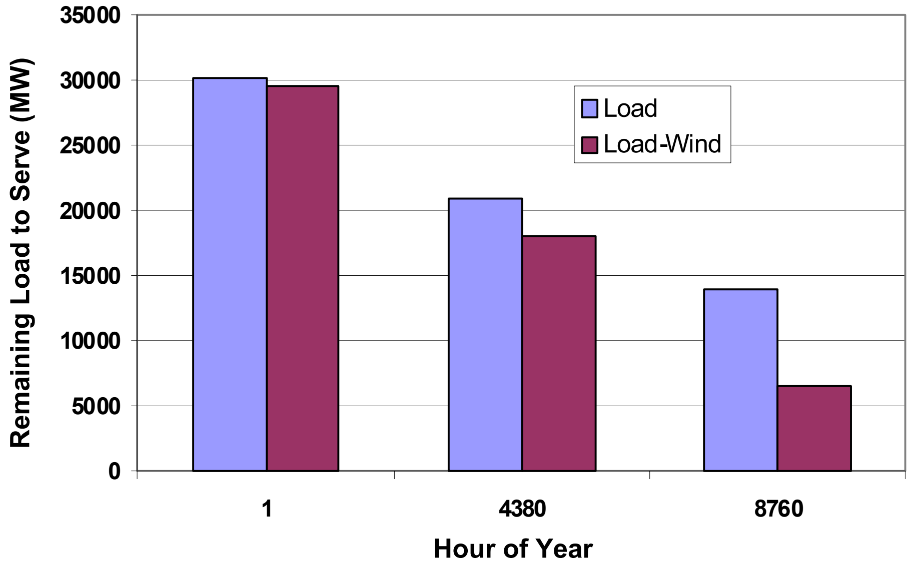

Figure 1.3 Impact of Wind on Remaining Load to Serve for Low, Median, and Peak Load Hours

Figure 1.4 illustrates the impact of 10,000 MW of wind on the balance of generation mix, in particular the amount of non-dispatchable generation such as nuclear or minimum operating points on hydro and large coal plants. For the peak-load hour, median-load hour and low-load hour, the solid lines show the amount of available maneuverable capacity with no wind generation, and the dotted lines show the show the amount of available maneuverable capacity with 10,000 MW of wind.

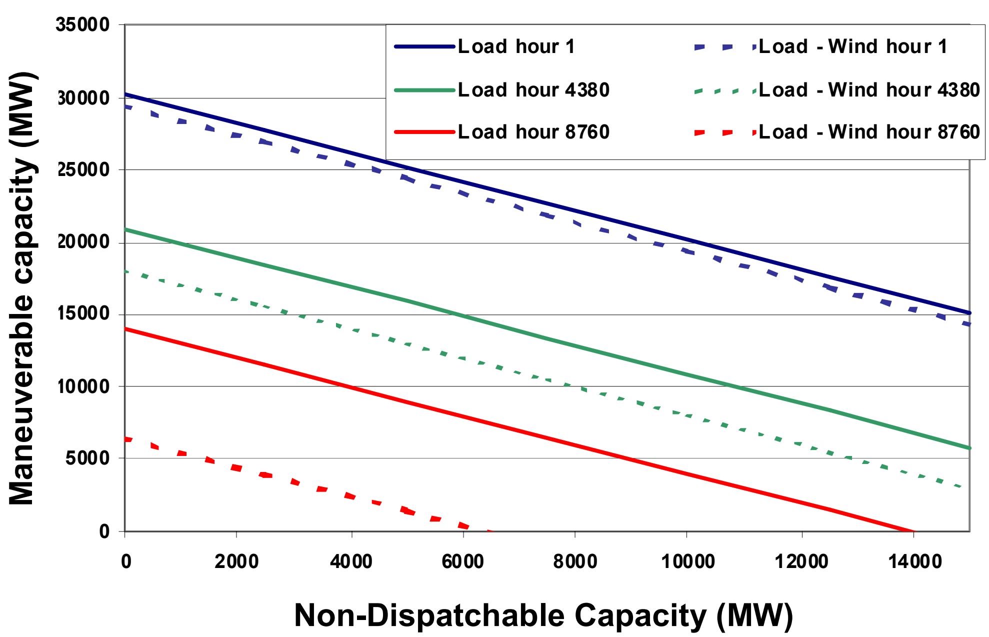

Figure 1.4 Remaining Maneuverable Capacity with 10,000 MW of Installed Wind

The plots show that with load-alone, as the non-dispatchable capacity approaches 14,000 MW for the low-load hour (8760), the maneuverable capacity approaches zero. At the median-hour (4380) and peak-hour (1), there is still "sufficient" maneuverable capacity available (6000 and 15,000 MW respectively) to meet system needs.

With 10,000 MW of wind, at the low load hour (8760), the system runs out of dispatchable generation when the non-dispatchable generation is only at 6,000 MW – quite a bit sooner than the load-alone case. The wind generation has minimal impact at the peak-hour (1), but the median-hour (4380) is now more interesting. At 14,000 MW of non-dispatchable generation, the amount of maneuverable generation at the median-hour has *decreased* by over 40%. This would indicate that at high penetrations of wind it might not be just a handful of low load hours that are cause for concern, but possibly *up half the hours in the year*.

Figure 1.5 below expands the picture for hour 4380 to include the various levels of year 2020 wind penetration discussed in the study. Even with 5,000 MW of wind, at 14,000 MW of non-dispatchable generation the amount of maneuverable generation at the median-hour is decreased by over 20%.

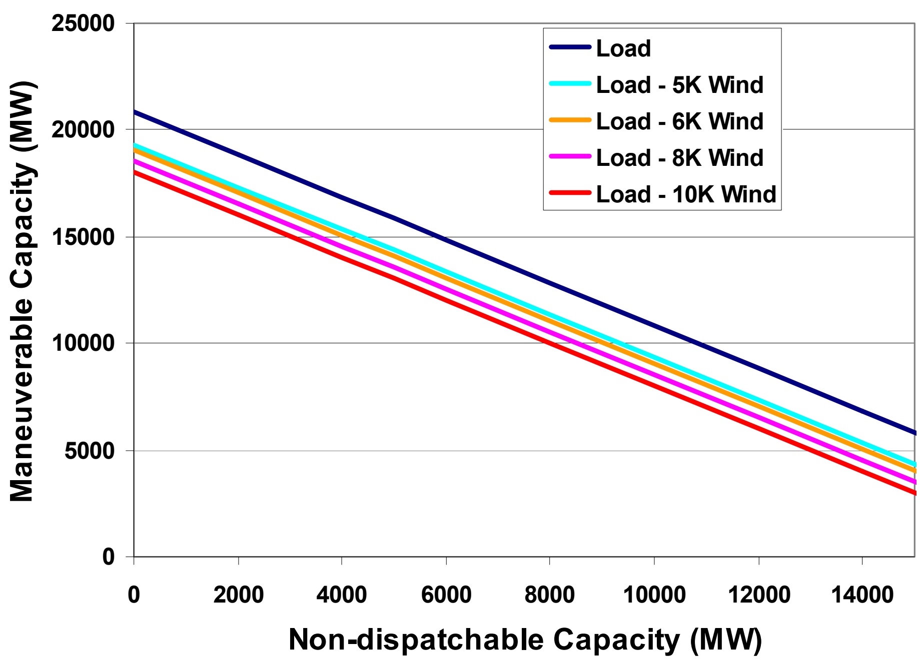

Figure 1.5 Maneuverable Capacity at the Median Hour (4380) for Load-Wind Scenarios

Figure 1.6 below plots the reduction in maneuverable capacity in the median hour as the amount of non-dispatchable generation is increased, for each load-wind scenario. Basically, the curves show the percent differences between the no-wind curve ("Load") and the load-wind curves ("Load - #K Wind") in Figure 1.5 for various levels of non-dispatchable generation. For example, based on the previous discussion, when non-dispatchable generation is 14,000 MW, we expect Figure 1.6 to show a 40% reduction in maneuverable capacity for 10,000 MW of wind and about a 20% reduction in maneuverable capacity for 5,000 MW of wind – which is the case.

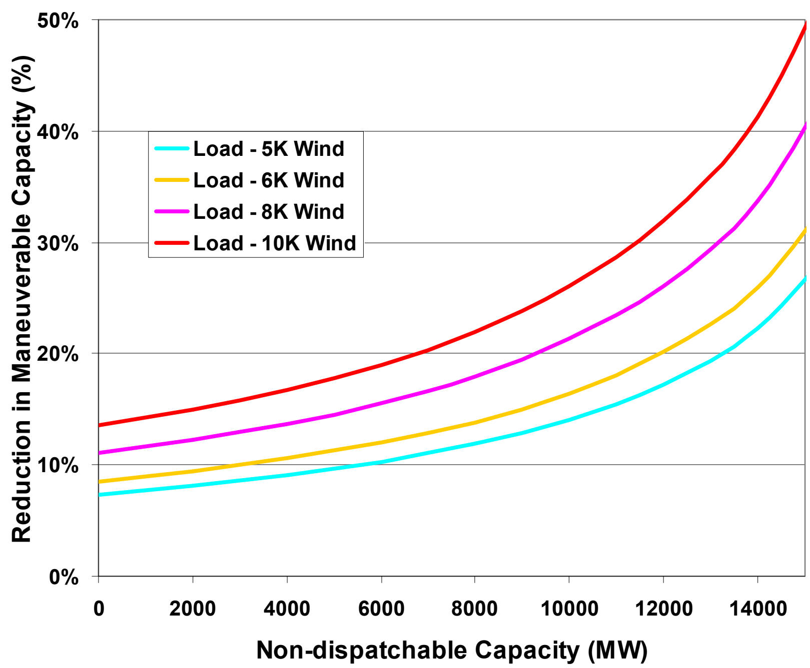

Figure 1.6 Percent Reduction in Maneuverable Capacity at the Median Hour for Load-Wind Scenarios

One way of using Figure 1.6 would be to set a limit on the amount of reduction allowed at the median-load hour to some specified value, for example 25%. Given a target wind penetration, this would define the maximum amount of non-dispatchable capacity that you would want on the system. For example, with wind penetration of 10,000 MW, and maximum reduction in maneuverable capacity set at 25%, the maximum amount of non-dispatchable generation is less than 10,000 MW. Conversely, given the amount of non-dispatchable capacity planned in the future, this curve would define the maximum allowable wind penetration.

This analysis has assumed that, for example, in an hour with 3,000 MW of wind generation the operator would back off a corresponding 3,000 MW of other generation, (which would decrease the maneuverability of the balance of generation). This would be necessary to maximize the economic value of the wind energy. Additional generation could be left on-line but this would not only reduce the value of the wind energy but could also lead to additional problems in low load hours because the system may not be able to back the generation down sufficiently to accommodate the wind energy. Higher penetration of wind resources would encourage the addition of fast-start, fast-ramping generation.

1.2.5 Low Load Period Mitigation Measures

The low load periods, illustrated in Figure 1.2, present a supply mix challenge that can be addressed in a number of ways:

- **Shed wind or use wind farm controls to provide flexibility** – Shedding the wind is a generally undesirable solution to the low load issue. For the 10,000 MW wind scenario, roughly 24% of the yearly wind energy output occurs below the load-alone minimum of 13,953 MW (see Figure 1.2). Rejecting or "throwing away" 24% of the wind energy produced in Ontario is inefficient and lessens the overall economic value of the wind farms for developers, the IESO, and the OPA. Advanced controls that control wind farm ramping rates and wind farm power output may afford system operators the flexibility needed to reasonably curtail power output and retain nearly the full value of the wind farm. This control, along with other mitigation measures, will significantly improve performance during those critical low load periods discussed earlier.

- **Export wind output to other control areas** – Neighboring utilities may be in a position to take the excess wind production during low load periods. However, many of Ontario's neighbors also have an interest in increasing the amount of wind generation on their systems. If Ontario's neighbors have similar penetrations to those explored in this study, then they, too, will be faced with the same low load issues and be looking for ways to deal with excess wind production.

- **Modify the load by adding loads during the low load periods** – There has been significant industry discussion regarding the complementary nature of wind and pumped storage hydro. While this is true, the market mechanism to exploit this natural fit is generally non-existent and the potential applications for pumped storage are limited. Instead of, or in combination with wind curtailment, adding load during the low load hours may help to lessen the impact on the online dispatchable generation resources. Pumped storage represents a potentially significant load that may help offset the need to curtail wind power output. The hydro stored energy could then be dispatched during periods where the load is near peak or the wind power output is low. Other future potential load modifications include, but are not limited to hydrogen production, large battery recharging, and ice production for daytime cooling.

- **Develop a more accommodating supply mix** – No mitigation measure is a replacement for a good supply mix strategy that addresses the low load issue. As the load moves down in the dispatch stack, the remaining generation will be subjected to increased ramping (both up and down) requirements due to the wind. A comprehensive plan to handle this additional ramping capability will reduce the number of other mitigation measures necessary, and maximize the value of all generation resources.

1.2.6 The Importance of Wind Farm Diversity

The importance of wind farm geographical diversity cannot be understated. These study results have assumed a wind group diversity that is aligned with previous wind study work performed by others. The results have demonstrated that good spatial diversity would virtually ensure that sudden disruptions in the aggregate wind output in the control area would not occur. The OPA and the IESO should encourage spatial and temporal diversity in the development of wind projects.

1.2.7 Area Congestion and Balancing

The study results show substantial benefits from spatial diversity within Ontario. As noted in the previous discussion, incentives to distribute wind projects throughout the system will reduce the risk and potential impacts of sudden common-mode disruptions. In practice, variations in power output from single wind plants or local groups of wind plants have the potential to create local or area operations problems. For example, the western portions of the province presently have limited transmission tying that area to the more tightly interconnected portions of the Ontario grid to the east. Wind variations within a subsystem can create incremental variation on tie lines (beyond that associated with load variation). If these variations drive tie lines against constraints (thermal or stability), then balancing requirements within the region may expand. Under some conditions, these area balancing requirements may exceed the capability of available resources.

When examining these area control issues, there is a critically important distinction to be drawn between those which impact system security and those which only impact current operating practice. When practice aimed at satisfying intra-area schedules are driven by jurisdictional or historical considerations, it is possible to reach the erroneous conclusion that the increases in variability and decrease in balancing resources within a particular area due to increased wind penetration make the system inoperable. Relaxed or otherwise modified scheduling constraints may be adopted without sacrificing security. On the other hand, stability and thermal constraints must be respected, and including spatial diversity in planning for maneuverability in the balance of portfolio will be required

1.3 Overall Summary of Operational Variability

Table 1.2 Summary of Overall Results

		2009 Load w/1310MW of Wind		2020 Load w/5000MW of Wind		2020 Load w/6000MW of Wind		2020 Load w/8000MW of Wind		2020 Load w/10000MW of Wind	
Time Scale	Technical Issue	Without Wind Generation	With Wind Generation	Without Wind Generation	With Wind Generation	Without Wind Generation	With Wind Generation	Without Wind Generation	With Wind Generation	Without Wind Generation	With Wind Generation
Years	Capacity Value	Cap. Value = 20% Overall, 38% in Winter and 18% in Summer		Cap. Value = 20% Overall, 42% in Winter and 17% in Summer		Cap. Value = 19% Overall, 42% in Winter and 16% in Summer		Cap. Value = 20% Overall, 41% in Winter and 17% in Summer		Cap. Value = 20% Overall, 41% in Winter and 17% in Summer	
Hours	Scheduling (3-hour delta variability)	--	--	σ = 2131	σ = 2179 (2.2%)	σ = 2131	σ = 2214 (3.9%)	σ = 2131	σ = 2254 (5.7%)	σ = 2131	σ = 2310 (8.4%)
	Largest 3-Hour Rise (MW)	--	--	6484	6838	6484	6919	6484	7023	6484	7586
	Largest 3-Hour Drop (MW)	--	--	-5526	-6012	-5526	-6539	-5526	-6904	-5526	-7339
	Scheduling (1-hour delta variability)	σ = 689	σ = 690 (0.2%)	σ = 781	σ = 804 (3%)	σ = 781	σ = 818 (5%)	σ = 781	σ = 837 (7%)	σ = 781	σ = 865 (10%)
	Largest Hourly Rise (MW)	2484	2511	2813	2857	2813	2853	2813	3414	2813	3780
	Largest Hourly Drop (MW)	-2029	-2101	-2338	-2398	-2338	-2666	-2338	-2730	-2338	-2990
Minutes	Operating Reserve (10-minute delta variability)	σ = 133	σ = 137 (3%)	σ = 150	σ = 178 (19%)	σ = 150	σ = 189 (26%)	σ = 150	σ = 203 (35%)	σ = 150	σ = 229 (53%)
	Largest 10-minute Rise (MW)	836	810	947	1009	947	997	947	1265	947	1468
	Largest 10-minute Drop (MW)	-992	-934	-1124	-1114	-1124	-1341	-1124	-1369	-1124	-1460
	Load Following (5-minute delta variability)	σ = 96.8	σ = 100.1(3.4%)	σ = 109.7	σ = 128.2 (17%)	σ = 109.7	σ = 136.1 (24%)	σ = 109.7	σ = 145.2 (32%)	σ = 109.7	σ = 161.3 (47%)
	Incremental Requirement (MW/5-minute)	10		56		80		107		155	
	Regulation (1-minute delta variability)	σ = 44.7	σ = 45.1(0.9%)	σ = 50.7	σ = 52.6 (4%)	σ = 50.7	σ = 53.4 (5%)	σ = 50.7	σ = 54.5 (6%)	σ = 50.7	σ = 56.5 (11%)
	Incremental Requirement (MW/1-minute)	1		6		9		12		18	

2 Introduction and Background

In recent years, wind generation has become a very attractive alternative to traditional power generation technologies. Several regions of the world, such as Germany, Spain, and Denmark, have successfully accommodated large penetrations of wind resources and the global trend is toward more wind in the future. A February 2006 press release from the Global Wind Energy Council (GWEC), proclaimed that 2005 was another record year for the wind industry with installations totaling 11,769 MW, and the amount of wind capacity added to the Canadian bulk power system increased by 53% in 2005.[1] In the release, Robert Hornung, President of the Canadian Wind Energy Association (CanWEA), stated, "*Canada's wind energy industry is growing by leaps and bounds – and that's great news for Canadians who research shows are strongly in favor of wind energy*." Although wind generation offers significant environmental advantages and zero-cost fuel, there are unique technical and operating considerations when integrating large amounts of wind generation into conventional bulk power systems.

In order to accurately assess the operational challenges presented by large amounts of wind, it is important to characterize the output of the wind farm sites identified by the Requesting Parties. AWS Truewind, which provides services for wind resource modeling and assessment, site identification, turbine layouts, and wind energy production forecasts, among others, was contracted to generate the wind power production profiles based upon data provided by wind developers in Ontario.

The overall objective of this study is to analyze the impact of wind generation on Ontario's bulk power system operation, *without transmission constraints*, for various wind penetration scenarios: 1310 MW by year 2009 and 5,000 MW, 6,000 MW, 8,000 MW, and 10,000 MW by year 2020. To accomplish this goal, the study focuses on the following key areas:

- Assessment of wind resource
- Determination of impact of wind resource variability on bulk power system operation for identified scenarios
- Determination of the capacity value of the wind
- Assessment of sudden weather changes on wind power production

The balance of this report consists of four main chapters that address the focus areas above. Chapter 3 details the development of the wind production data, Chapter 4 analyzes of the wind capacity value, Chapter 5 assesses of the statistical variability of wind, load and combined load and wind, and discusses the impact of load and wind variability on the Ontario bulk power system operations (without considering transmission constraints). In addition, there are several Appendices with supporting material.

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[1] GWEC, *Record year for wind energy: Global wind power market increased by 40.5% in 2005*, February 2006, http://www.gwec.net/index.php?id=30&no_cache=1&tx_ttnews%5Btt_news%5D=21&tx_ttnews%5BbackPid%5D=4&cHash=d0118b8972

2.1 Terminology and Nomenclature

The study of large penetrations of wind generation on the bulk power system is a relatively new and evolving field. As such, the nomenclature and terminology used in studies varies widely. The following is a set of terms used throughout this report with their associated definition:

- **Capacity Value (%)** = Average hourly wind power output during the periods when load is within 10% of its peak. This is per unit of wind nameplate rating.
- **Load-Wind** = Simply the load minus the wind power output. This is sometimes called the net load.
- **Deltas (Δ)** = Difference between successive data points in a series (load, wind or load-wind)
- **$\sigma_{\text{Load (x min or hour)}}$** = The standard deviation of the load deltas (Δ) for a time period of x minutes or hours
- **$\sigma_{\text{Load-Wind (x min or hour)}}$** = The standard deviation of the load minus wind deltas (Δ) for a time period of x minutes or hours
- **$3\sigma_X$** = Three times the standard deviation of the deltas (Δ) for the period x or 99.73% of all values in a normally distributed population. This is used to define incremental requirements to maintain existing performance
- **Regulation =** Adjustment of generation units to accommodate minute-to-minute system variations. Incremental regulation requirements to maintain existing performance is defined as the difference between the **$3\sigma_{(1min)}$** for load-alone and load-wind.
- **Load Following =** Adjustment of generation units to accommodate 5-minute system variations. Incremental load following requirements to maintain existing performance is defined as the difference between the **$3\sigma_{(5min)}$** for load-alone and load-wind.
- **Operating Reserves =** The amount of generation necessary to compensate for the loss of the largest single generation unit connected to the bulk power system. Additional operating reserve requirements are a function of the largest (positive) load-wind delta and the maximum wind-alone drop over a 10-minute period.
- **Max. Positive Delta (Δ) =** The maximum positive (increase) difference between two successive points in a series of data (load, wind or load-wind).
- **Max. Negative Delta (Δ) =** The maximum negative (decrease) difference between two successive points in a series of data (load, wind or load-wind).

2.2 Operational Impact Review

The power system is an interconnected dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. From a control perspective, the load is the primary independent variable – the driver to which all the short-term controllable elements in the power system must be positioned and respond. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and nature) of load served by the system. The performance of the power system is highly dependent on the ability of the system to accommodate expected and unexpected changes and disturbances while maintaining quality and continuity of service to the customers.

As illustrated in Figure 1.2, there are several time frames of variability, and each time frame has corresponding planning requirements, operating practices, information requirements, economic implications and technical challenges. Much of the analysis presented in this report is aimed at quantitatively evaluating the impact of significant wind variability in each of the time frames on the performance of the Ontario bulk power system.

Figure 2.1 shows four timeframes covering progressively shorter periods of time. In the longest timeframe, planners must look several years into the future to determine the infrastructure requirements of the system. This timeframe includes the time required to permit and build new physical infrastructure. In the next smaller timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this time frame, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. This is the shortest timeframe in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made the day ahead are implemented and refined to meet the changing load. In Ontario, the economic dispatch process issues load following commands to individual generators at 5-minute intervals. In the shortest time frame (at the bottom of the figure), cycle-to-cycle and second-to-second variations in the system are handled primarily by automated controls. The system automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e. are detected at the generating plant or substation). In addition, a subset of generators provide regulation by following commands from the centralized automatic generation control (AGC), to meet overall system control objectives including scheduled interchange and system frequency.

In this study the operational impact of load and wind variability on the Ontario bulk power system is determined in each of the following timeframes: three-hour – sustained ramping; one-hour – generation scheduling; ten-minute – operating reserves requirement; five-minute – load-following requirement; one-minute – regulation requirement.

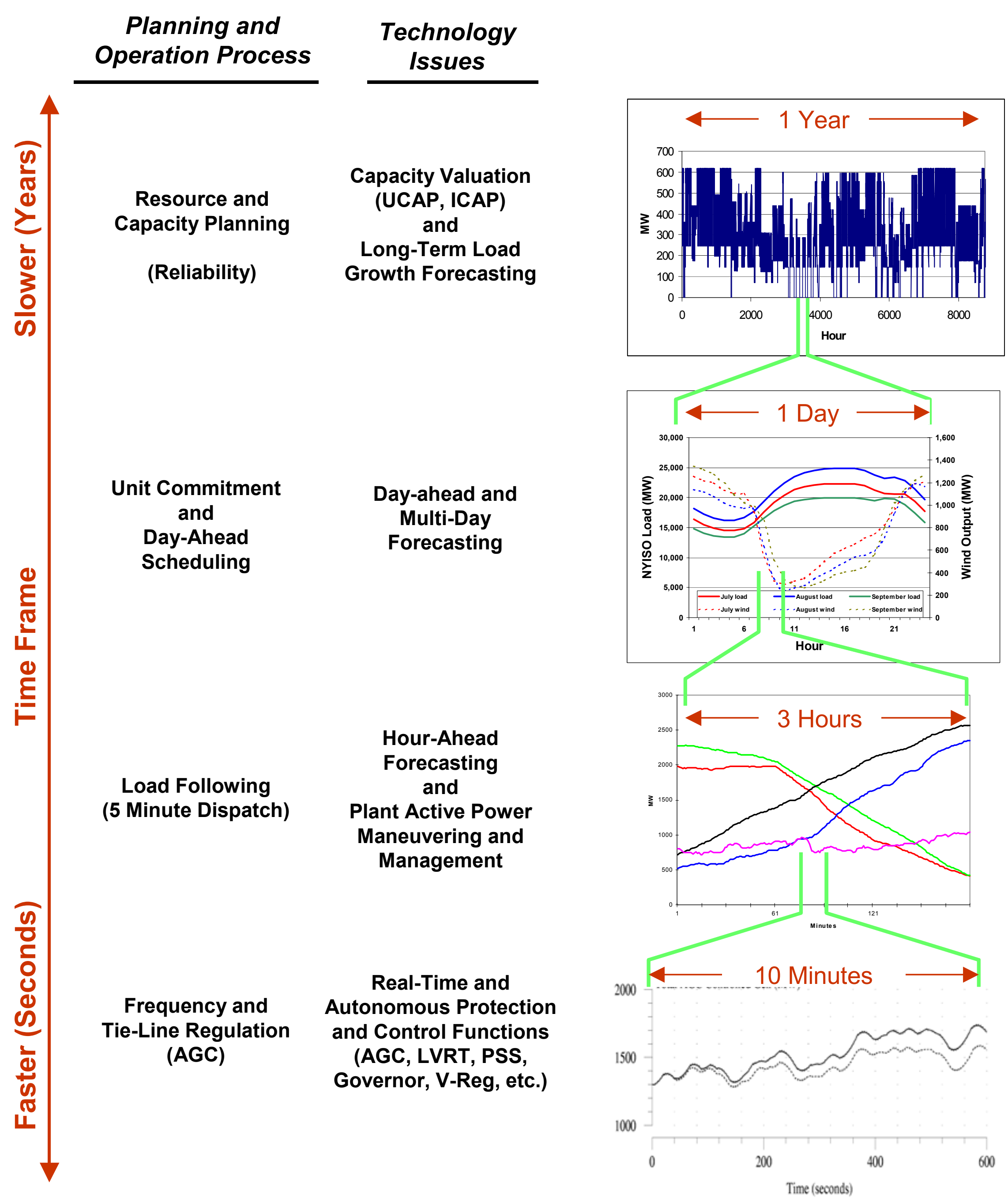


Figure 2.1 System Planning and Operations Overview

3 Wind Production Profiles

3.1 Introduction

This section describes the methods AWS Truewind has used to produce the 10-minute and 1-minute wind energy production data used in this study. The goal of wind production profile creation was to model the time-varying behavior of wind generation in a realistic manner, taking into account existing and planned wind projects in Ontario, and likely areas for future wind development. This was accomplished using wind data collected by project developers at numerous sites in the province.

3.2 Input Data

The NDA template, which was provided by the OPA, restricts the use of the data to this study, and bars AWS Truewind from releasing the data to others (including GE Energy and the Requesting Parties) except if aggregated with data from other masts so that no single mast can be identified. This and other restrictions in the NDAs prevent AWS Truewind from revealing specific information about wind monitoring stations, but they can be described a general way.

The developers provided usable data from 34 tall towers in Ontario. The sites represent most of the areas under active development today. However the density of coverage varies greatly. Some areas, such as the shores of Lake Ontario and Lake Erie (six stations), the eastern shore of Lake Huron (10 stations), points between Lake Erie and Georgian Bay (seven stations), and the eastern and northern shores of Lake Superior (eight stations), are relatively well represented, whereas others that are of interest for project developers (or may be so in the future) are represented by few or no masts. The lack of coverage in some development areas and the overall excess of projects over masts reduce the geographic diversity observed in the wind data, as further discussed in Section 5.6.

The temporal coverage of the data varies as well. A specific goal of this task was to produce a data set spanning at least one continuous year to enable GE Energy to assess the impacts of wind on the power system operation in every season. To this end, AWS Truewind requested as much data as possible from the developers for periods between September 2003 and the present. After aligning the time stamps of the data files and flagging gaps, it was determined that 2005 had the best data recovery overall and would therefore be the most suitable period for the study. Nevertheless, three of the stations had poor data recovery in 2005 and had to be dropped, leaving 31.

Although all of the data used had been validated (quality-controlled) in advance, it was still reviewed to check for unrealistic values. All missing or presumably invalid data were then replaced (reconstructed) in two steps. Firstly, gaps of less than six hours were filled in by interpolating between the nearest valid data records before and after the gaps. Secondly, for gaps greater than 6 hours, linear regression relating valid wind speeds at each mast (the target mast), concurrent speeds at the other masts (the replacement masts) were performed to reconstruct the missing data. For each target mast, the replacement mast with the highest correlation to the target was used. If that replacement mast had gaps in some of the same periods, the mast with the next highest correlation was used and the process was repeated until all the gaps were filled.

Missing temperature records were reconstructed in a similar manner. (The temperature, along with the elevation, determines the air density.) Direction data were reconstructed as well, although since direction has only a secondary influence on the predicted plant output, direct substitution was used in that case.

The end result was a set of data files containing a complete year of 10-minute wind speed, direction, and temperature data for each of the 31 wind monitoring stations. These data files formed the basis for the estimation of the 10-minute wind plant output, and subsequently the 1-minute output.

3.3 Assignment of Stations to Planned and Future Project Sites

The next step in the analysis was to assign the stations to existing, planned ("signed"), and future projects. AWS Truewind obtained the locations and MW rated capacities of the existing, signed, and future projects from "Analysis of Future Wind Farm Development in Ontario," a report prepared by Helimax Energy, Inc., for the Ontario Power Authority in March 2006. The future project sites were chosen by Helimax through a GIS-based site-screening process using the Ontario Wind Atlas to estimate plant energy production. Helimax provided GIS files showing the locations of both the signed and future projects. The Helimax report identified 12 signed projects totaling 1,310 MW and 60 sites representing an additional potential of 8,191 MW.

The Helimax report also listed projects that are proposed or under development, but are not signed. There are 61 such projects[2], with a total rated capacity of 5,168 MW. These projects were not modeled in this study. In addition, we ignored six currently operating projects listed in the Helimax report were not included since they have a combined rated capacity of only 14.6 MW.

Following this, wind-monitoring stations were assigned to the Helimax sites. The main criterion was geographic proximity, although other factors (such as whether a particular site and station were both near a lake shore) were also considered. However, it was not possible to have a one-to-one correspondence between the stations and sites. One reason is that some sites are not near any stations. Four of the future sites were dropped for this reason. This reduced the number of future sites from 60 to 56 and the total rated capacity of future projects from 8191 MW to 7417 MW (the signed projects were unaffected). Another complication was that there are fewer wind monitoring stations than project sites. Thus, one station must often be assigned to more than one site. Finally, in some areas there were more stations than there were nearby project sites. Four stations could not be used for this reason, leaving a total of 27.

[2] The data obtained by Helimax was from public records

3.4 Conversion to Plant Output

Once the stations were assigned to the Helimax sites, the 10-minute wind speeds from the stations were scaled (adjusted by a constant ratio) in such a way that, for each site, the mean speed for the corresponding station matched Helimax's estimated speed. For the signed projects, Helimax did not provide an estimate of the mean speed, so AWS Truewind relied on their own estimates extracted from the Ontario Wind Atlas. The average adjustment ratio was 1.10, and the minimum and maximum adjustments were 0.85 and 1.36, respectively. The fact that the average ratio was greater than 1.0 is to be expected, since most of the wind data were collected at heights below the assumed 80 m turbine hub height.

The wind speeds were then reduced by a directional loss factor ranging from 6% to 10%. This factor is intended to represent, in part, the impact of upwind turbines on the wind speed experienced by downwind turbines; this impact, or wake loss, typically varies by direction because of unequal spacing of turbines parallel and perpendicular to the prevailing wind direction. The loss factor also incorporates the effects of blade soiling and icing, which reduce turbine efficiency.

The air density for each 10-minute record at each site was also estimated using the temperature data from each station and the site evaluations. The amount of energy produced by a wind turbine for a given wind speed varies with the air density.

Next, the wind speed for each 10-minute record for each site was applied to the generic 3 MW wind turbine power curve assumed in the Helimax study. To account for the air density, the wind speed was scaled by the cube root of the ratio of the site air density to the nominal (sea-level) air density at which the power curve was specified. The output was then scaled up according to each project's assumed rated capacity.

Finally, the plant output was reduced by 4% to account for normal plant electrical and availability losses. The combined loss, including wakes, blade soiling and icing, and electrical and availability losses, ranged from about 12% to 16%, a typical range for large wind projects in this region.

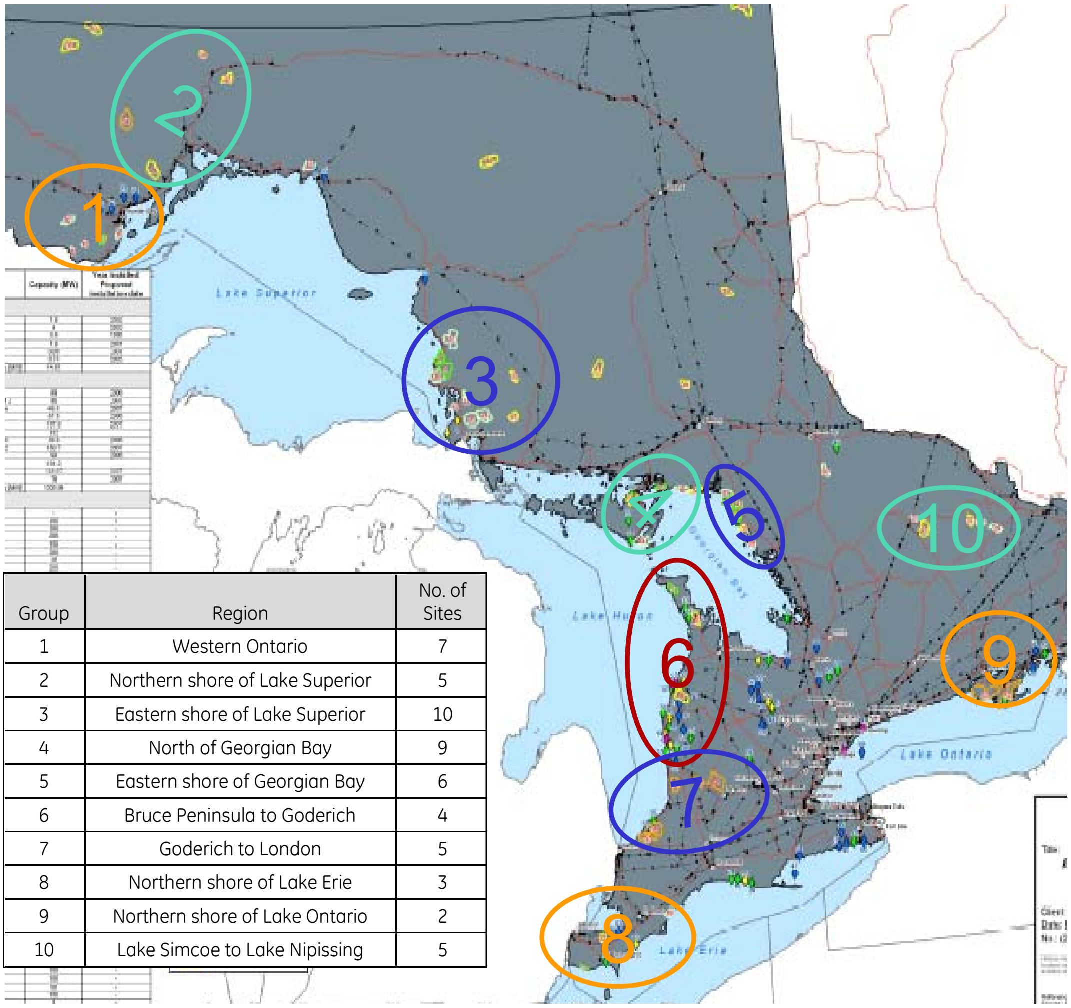
3.5 Aggregation of Output Data

In order to disguise the data from individual stations (in conformance with the NDAs), it was necessary to aggregate the output of individual sites. In addition to the signed projects, which were combined into one group, AWS Truewind constructed 10 groups of new project sites with combined rated capacities ranging from 143 MW to 1792 MW. The groups correspond to broad geographic areas, and are numbered starting from extreme western Ontario, moving across the northern shore of Lake Superior, and then moving south towards Lake Erie. The groups are listed in Table 3.2, along with their rated capacities and estimated net annual generation, and the approximate locations are shown in Figure 3.1.

Helimax's estimates of the net annual generation for each group are provided for comparison. On average, the estimates are about 5% lower than Helimax's; the difference ranges from 2% to 7%. Since the mean wind speeds in this process were scaled to match Helimax's, the power curve is the same, and Helimax's assumed loss – 15.6% - is comparable to that obtained here. The differences must be attributed to the use of observed wind speed distributions rather than the modeled Weibull speed distributions assumed by Helimax.

Table 3.2 Wind Groups Constructed to Aggregate Site Data

Group	Region	No. of Sites	MW Capacity	Annual Energy (GWh)	Helimax Energy (GWh)
1	Western Ontario	7	827	2044	2101
2	Northern shore of Lake Superior	5	783	1817	1931
3	Eastern shore of Lake Superior	10	1752	4303	4542
4	North of Georgian Bay	9	1267	2985	3189
5	Eastern shore of Georgian Bay	6	773	2004	2051
6	Bruce Peninsula to Goderich	4	617	1498	1577
7	Goderich to London	5	514	1163	1253
8	Northern shore of Lake Erie	3	143	364	392
9	Northern shore of Lake Ontario	2	292	698	742
10	Lake Simcoe to Lake Nipissing	5	449	1094	1165
Signed		12	1310	3388	NA
Total		68	8727	21358	



Group	Region	No. of Sites
1	Western Ontario	7
2	Northern shore of Lake Superior	5
3	Eastern shore of Lake Superior	10
4	North of Georgian Bay	9
5	Eastern shore of Georgian Bay	6
6	Bruce Peninsula to Goderich	4
7	Goderich to London	5
8	Northern shore of Lake Erie	3
9	Northern shore of Lake Ontario	2
10	Lake Simcoe to Lake Nipissing	5

Figure 3.1 Location of Wind Groups 1 through 10

3.6 Limitations of the 10-Minute Data

As noted earlier, the lack of stations in some development areas and the overall excess of projects over stations reduce the geographic diversity represented in the data. This suggests that the wind generation profiles produced probably overstate the variability of the combined output of the wind projects. The degree to which the variability is overestimated is difficult to determine. However, it is likely that it is greatest for 10-minute fluctuations and that it decreases for longer time scales. Ten-minute fluctuations are virtually uncorrelated between different wind project sites, even if they are just a few kilometers apart. Therefore, combining the output of several projects should greatly reduce the 10-minute fluctuations as a fraction of the total output. Having fewer stations than project sites implies that much of this "diversity benefit" may be lost in our simulated data at this time scale.

On the other hand, over periods of several hours or more, wind fluctuations tend to be more correlated between projects spaced as many as hundreds of kilometers apart. On such time scales, the lack of geographic diversity in the data probably makes little difference to the overall variability of the combined plant output.

With some research, it might be possible to simulate the geographic diversity lacking in the present database using a time-filtering approach. This method recognizes that geographic diversity smoothes fluctuations in the wind, as fronts, storms, and other systems pass different project sites at different times. Simple geographic arguments may be used to construct a plausible method. Wind correlation and the impact of diversity on wind output over small time frames is further discussed in Section 5.6.

3.7 One-Minute Data

From an examination of the 10-minute wind data, twenty-four periods lasting from 3 to 24 hours (totaling of 180 hours) were identified for one-minute data samples. To produce the required data, AWS Truewind used one-minute-resolution plant data from a 105 MW wind project in northwestern Iowa, which had been obtained for a previous project from the National Renewable Energy Laboratory (NREL). A computer program was then written to carry out the following tasks:

- Extract one-minute deviations from the 10-minute trends in the data, excluding data flagged as invalid.
- Identify several thousand three-hour consecutive blocks of one-minute deviations.
- Scale the deviations up or down according to the size of the project to imitate the smoothing that occurs when the output of individual turbines is aggregated. (Since individual turbines experience uncorrelated one-minute fluctuations, the combined output of many turbines has a much lower overall variability, as a fraction of rated capacity, than a single turbine; furthermore, the greater the number of turbines in a project, the smaller the variability of their combined output. A logarithmic relationship, which was derived in the previous project, was employed between plant size and output variability.)
- Apply the scaled fluctuations to the 10-minute data to produce simulated one-minute wind plant data for each site for each of the desired periods. For each site and period, a different three-hour block of one-minute deviations was used to ensure zero correlation between sites. Furthermore, the blocks of deviations were chosen at random from the thousands previously identified, the only restriction being that the average capacity factor for the block chosen be similar to that of the site in the period chosen. (This last restriction is to ensure that the program faithfully captures the different patterns of fluctuation that occur at different points on a turbine's power curve. In the middle of a turbine's power curve, fluctuations in wind speed tend to produce relatively large changes in output; whereas at either end of the curve, the output becomes insensitive to speed and the fluctuations tend to disappear.)

As a final step, the one-minute data for each site were aggregated to the same eleven groups, and the aggregated data was used for the operational analysis

4 Capacity Value Analysis

The true capacity value of wind generators is often a source of great debate and concern among system operators. Wind generators are non-dispatchable resources because their power output varies according to the wind conditions at any given instant in time, and is difficult to predict or forecast with any degree of accuracy. The unpredictability of the wind is a reasonable concern that certainly has an impact on the overall value of the resource. Calculating the value of the wind during the highest risk periods throughout the year provides an assessment the value of the wind resource. The classical definition of capacity ***factor*** is the *average power output* during all the hours over a defined period of time divided by the nameplate rating of the generation resource. Capacity ***value*** is a measure of the generation resource output during critical periods throughout the year, such as when the load is within 10% of its peak. PJM and NYISO define *capacity value* as the capacity factor during those hours of the day when the peak load is likely to occur in the peak months of June, July, and August. In this study, the capacity value is defined as the average hourly wind power output during the periods when load is within 10% of its peak. This is per unit of the wind power output nameplate rating.

Unlike firm, dispatchable generation resources, wind generator output varies on a continuous basis. Due to this variation, the value of the wind generator is a smaller percentage of the installed nameplate value when compared to fully dispatchable generators. In this study, the capacity value of wind is calculated as the average hourly wind power output during the periods when the load is within 10% of its peak. This value is presented as a percentage of the total installed nameplate value of the wind resources. Based upon previous study[3] results, this method of calculating capacity value has been found to provide results comparable to traditional loss of load expectation (LOLE) methods.

As shown in Figure 4.1, the average overall capacity value is generally insensitive to the wind penetration level and ranges between 38% to 42% during the winter months (November to February) and 16% to 19% (June to August) during the summer months. Good wind geographic diversity and the scaling of wind data from the same groups to derive overall wind power output tend to cause the insensitivity to penetration level. The overall yearly capacity value is approximately 20% for all scenarios. In other words, 10,000 MW of installed nameplate wind capacity is equivalent to approximately 2,000 MW of firm generation capacity. The average capacity value of 20% was arrived at both by looking at the contribution of wind when the loads were within 10% of the peak load as well as looking at the contribution during pre-selected hours in June, July and August. Both of these methodologies look at the timing of the wind and are not sensitive to penetration levels. We then determined the modified load after the addition of the first 5,000 MW of wind and used these values as the starting point to determine that the capacity of the *second* 5,000 MW of wind was reduced to only 16%, indicating that some slight

[3] GE Energy, *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, And Operations*, March 2004, http://www.nyserda.org/publications/wind_integration_report.pdf

saturation has taken place. The overall capacity value is heavily weighted towards the summer value because nearly 87% of the hits (periods within 10% of the load peak) occur during the summer months. The calculated capacity value is based upon a single year of wind and load data. Given only one year of data, we are unable to provide a statistically based confidence level in the reported results. As suggested in Section 1.2.1, it is recommended that wind capacity value be monitored to validate these results.

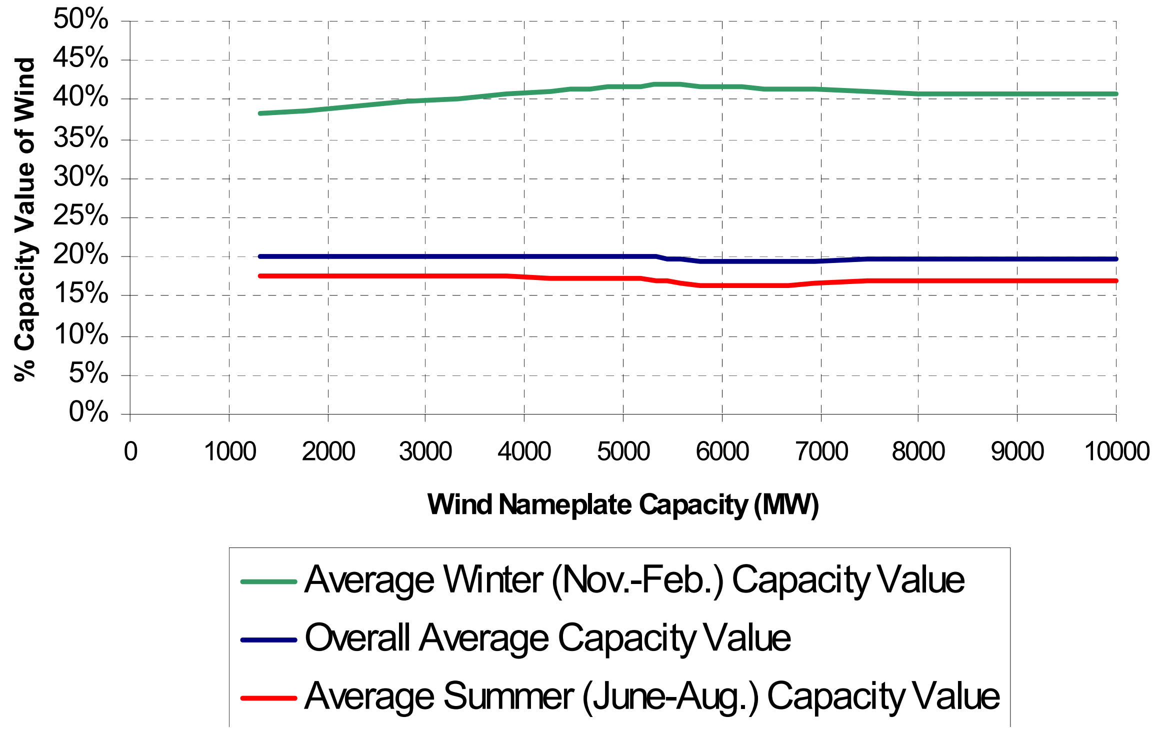


Figure 4.1 Wind Capacity Value vs. Wind Nameplate Capacity

This section serves to provide background information on the methods used to arrive at these results and some additional analysis of the data. Although a detailed analysis was performed for all of the scenarios, the 10,000 MW wind scenario is presented in this section to exemplify the type of analysis completed for each scenario.

Table 4.1 Study Scenarios

Scenario Number	Description	Nameplate as a % of Peak Hourly Load	% of Total Yearly Energy
1	2009 Load plus 1,310MW of planned/existing nameplate wind capacity	4%	2%
2	2020 Load plus 5,000MW of nameplate wind capacity	17%	7%
3	2020 Load plus 6,000MW of nameplate wind capacity	20%	8%
4	2020 Load plus 8,000MW of nameplate wind capacity	27%	11%
5	2020 Load plus 10,000MW of nameplate wind capacity	33%	13%

4.1 Capacity Value Sensitivity to Wind

With only a single year of synchronized wind and load data, it is possible that the sample year (2005) was not truly representative of a typical year, and the wind during the year was coincidently well matched (or unmatched) to the system peaks. In other words, by pure luck the wind power output just happened to be "good" (high capacity factor) during the top 10% of the load periods and, therefore, the calculated capacity value is not representative of future expectations. On the other hand, the sample could demonstrate an uncharacteristically low capacity value because the wind happens not to be present during the peak periods. The best scenario would be to perform the analysis with several years of historical wind and load data. Since this volume of historical data was not available, the next best method of evaluating the sensitivity of capacity value to wind and load coincidence is to temporally *shift* the wind power output. Shifting (see Appendix A, section 6.3) refers to the process of moving wind power data forward by 1, 2, or 3 days while leaving the load data intact. Wind power output at any given instant, time t, is linked (auto-correlated) to the power output at times t-1 and t+1. The coupling between time periods or "persistence" is quantified in terms of state transition probabilities. See Chapter 5 for more information on state transition probabilities. Shifting the wind data retains the temporal coupling of wind from one time period to the next while "simulating" a different wind pattern relative to the load. Figure 4.2 shows the results of shifting the wind by 1, 2, and 3 days on the overall capacity value of the wind, for the 2020 load with 10,000 MW of wind scenario. It also shows how the capacity value changes as the threshold for which the wind value is counted (per unit of peak) is modified.

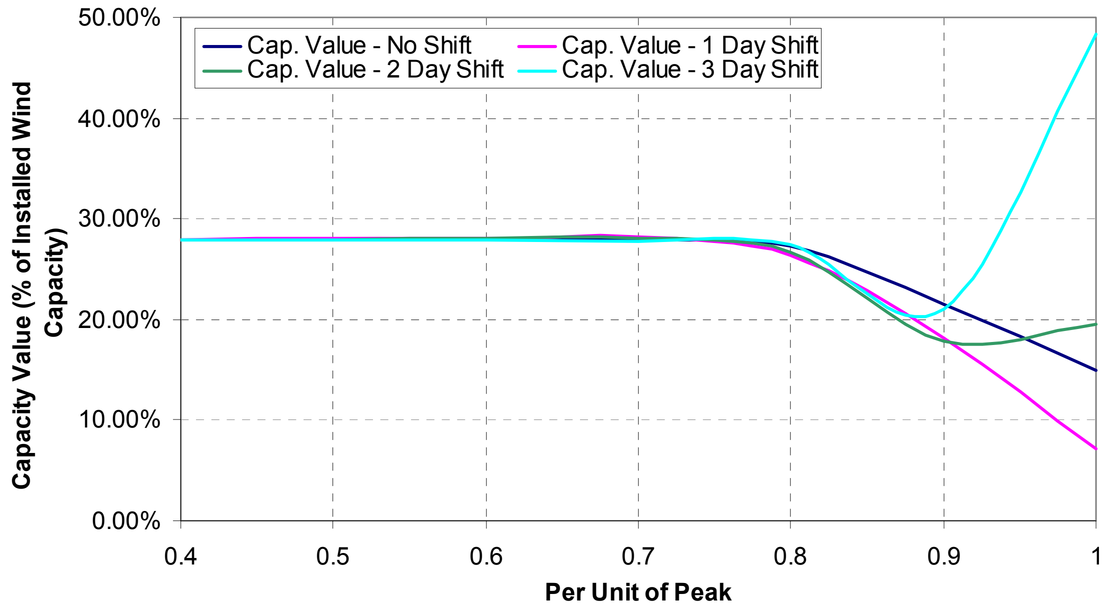


Figure 4.2 Sensitivity of Capacity Value to Shifting of Wind - 2020 Load with 10,000 MW of Wind

The results reported in the executive summary are the averaged capacity values calculated for each of the shifts (0, 1, 2, and 3 days) for a threshold of 0.9 per unit of peak (within 10% of the peak). In this case, the average overall capacity value is 20%. In other words, 10,000MW of wind has a value equivalent to 2,000 MW of firm generation. As can be seen in the figure, the capacity value is relatively insensitive to the per unit peak threshold until around 0.8 per unit. After 0.8 per unit, the curves begin to diverge and above 0.9 per unit, the curves become widely varied and separated. As the per unit of peak threshold is increased, the number of hours out of the year that are used to calculate the capacity value decreases until, at 1.0 per unit, only a single hour out of the year is being used for the calculation. This helps to explain why the capacity value varies significantly beyond 0.9 per unit (small number of data points). As the per-unit of peak threshold gets smaller (moving to the left along the x-axis), more and more of the hours are used in the calculations and, therefore, the capacity value approaches the overall yearly capacity ***factor***.

4.2 Monthly Capacity Value

Seasonal changes in weather patterns can significantly impact the wind power output. It also has a significant impact on the characteristic load patterns. The variation of the capacity value on a monthly basis is evaluated in this section. As shown in Figure 4.3, with the threshold set at 0.9 per unit, the majority (over 80%) of the "hits" or number of periods during which the load exceeds 0.9 per unit of the peak occur during the summer months from June to August. This particular figure also shows the average capacity value for the no shift case. Figure 4.4 shows the capacity value on a monthly basis with shifting for 2020 load with 10,000 MW of wind.

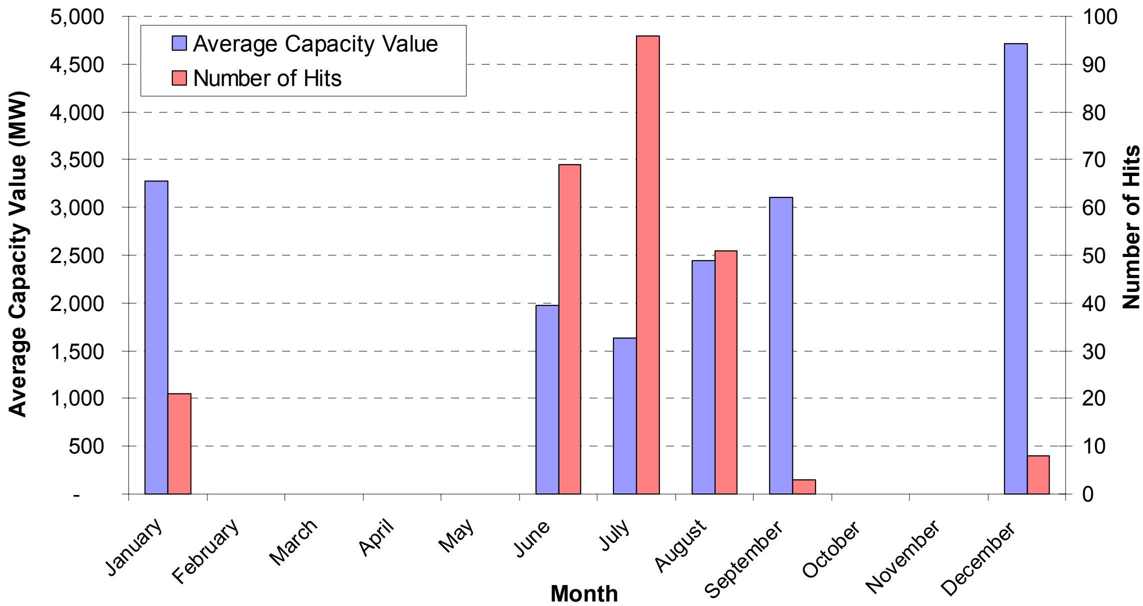


Figure 4.3 Monthly "Hits" and Average Capacity Value for No Shift - 2020 Load with 10,000 MW of Wind, Threshold = 0.9 pu of Peak Load

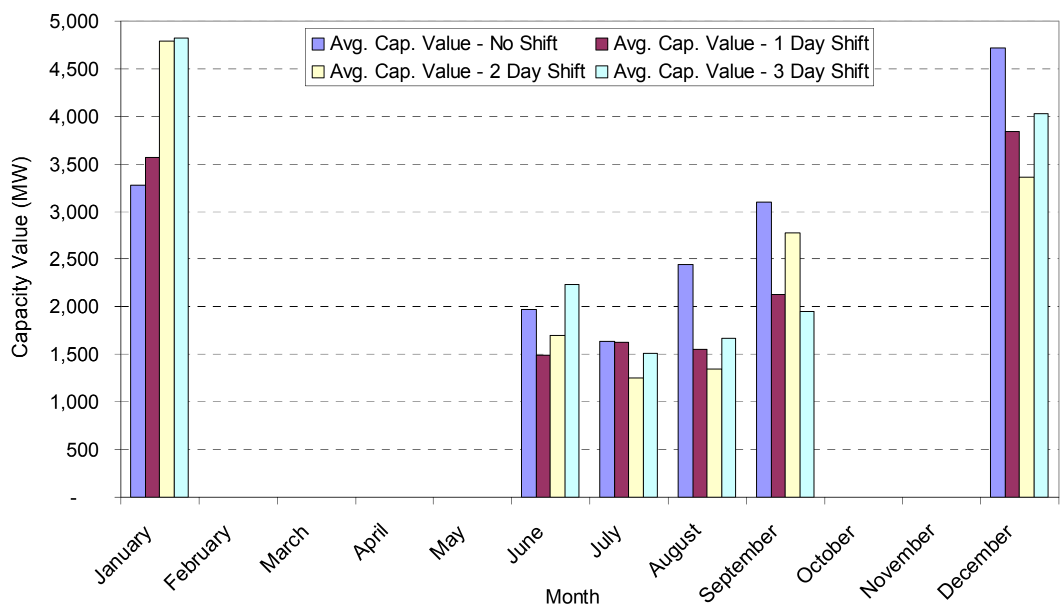


Figure 4.4 Monthly Capacity Value with Shifting- 2020 Load with 10,000 MW of Wind, Threshold = 0.9 pu of Peak Load

Although the number of hits is far fewer during the winter months, the power output during those periods is roughly twice the output during the summer month hits. Since Ontario is now a summer peaking province, these results are consistent with expectations. Even though the winter capacity value is 41% and the summer capacity value is 17%, the overall capacity value is only 20%. This is because the overall capacity value is heavily weighted towards the summer months since the majority of "hits" occur during those months.

4.3 Daily Capacity Value

Another way to look at the capacity value is on a daily basis. What is the wind power output during the peak hours of the day? Figure 4.5 and Figure 4.6 show the number of hits and average capacity value for each hour of the day during the winter and summer months, for the 2020 load with 10,000 of wind, and threshold = .9 pu of peak.

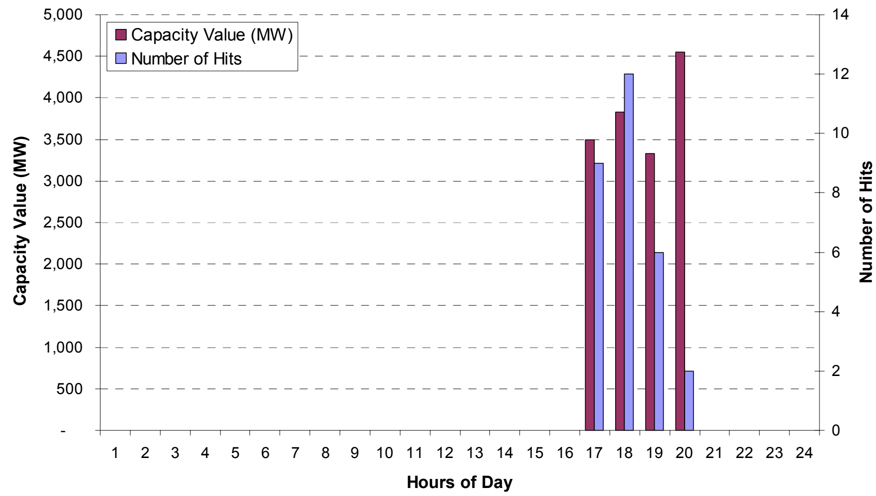


Figure 4.5 Capacity Value and Hits During Winter Hours of the Day (No Shift)

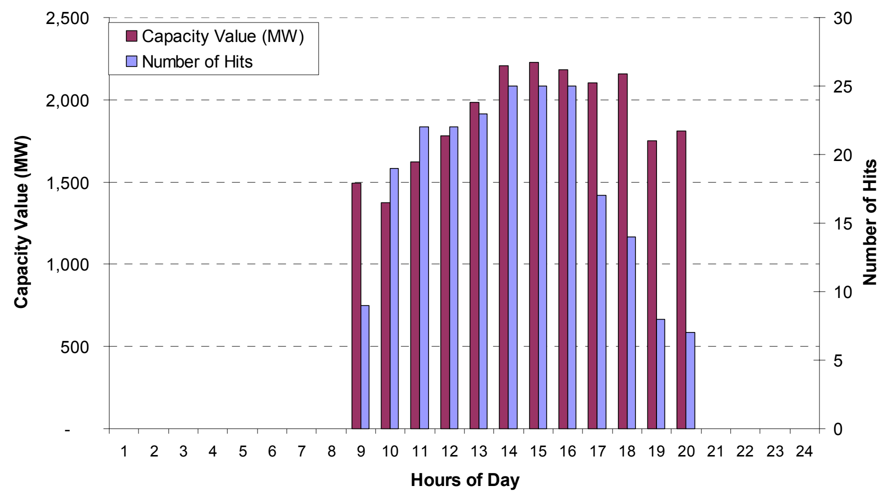


Figure 4.6 Capacity Value and Hits During Summer Hours of the Day (No Shift)

During winter from 5pm to 8pm, the load reached 90% of the yearly system peak roughly 29 times over the course of the year. At 5pm, the system load reached 90% of peak 9 times and the average wind power output was approximately 3,500 MW during that hour. Similarly, at 8pm there were 2 hits and the average wind power output was approximately 4,500 MW. During the summer, the number of hits are far greater and the capacity value is roughly half that of the winter months. However, in both seasons, the value of the wind during the peak hours of the day is generally consistent with the overall average winter and summer capacity values of 40% and 20% respectively.

5 Statistical Variability and Operational Impact Analysis

One of the key questions that this study addresses is, what is the impact of wind variation on the intrinsic load variability already experienced by the Ontario Bulk Power System? Power systems are dynamic, existing in a continuously changing environment, and are impacted by factors that change from second-to-second, minute-to-minute, hourly, seasonally and year-to-year. In the various time frames of operation, balance must be maintained between the load on the system and the available generation. The fact that the load is constantly changing means that its variability must first be understood in order to assess the impact of another variable element, (such as wind), on system operation. Statistics is an extremely useful tool for understanding and describing variation in data.

5.1 Introduction to Descriptive Statistics

Statistics (in particular, *descriptive* statistics) is the branch of mathematics that deals with characterizing the nature of random variables. A random variable is a quantity whose value is determined by the outcome of a random experiment. In this case, a random experiment can be as simple as sampling the system load at a particular time. In this example, the system load is the random variable, and the value of the load (MW) is the observation. Each time the load is observed (or sampled), the value will be different because -- *load varies*. This variation in load, driven largely by consumer behavior, has a distinct daily, weekly and seasonal trend that can be easily observed. For example, Figure 5.1 shows a typical winter daily load profile for the Ontario Power System. While each winter day exhibits a similar trend over the 24-hour cycle, within smaller timeframes there is significant "random" variation around the daily trend, as shown in the one-hour window in Figure 5.1.

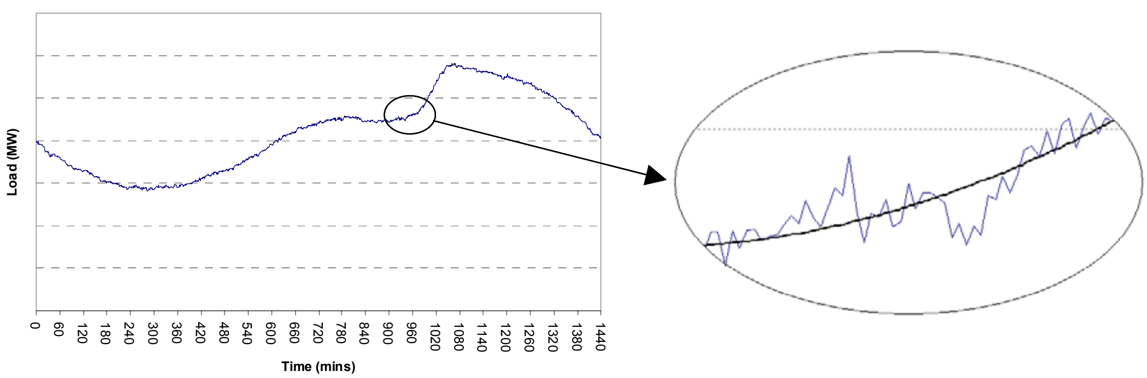


Figure 5.1 Typical Winter Daily Load Profile and Expansion of a One-Hour Window

If a smaller time window were observed, the variations around the trend would be even more random in nature. If the data were de-trended, the residuals, i.e. the short-term variations, could be more easily observed and studied without the influence of the long-term trend.

One popular method of de-trending non-stationary time series data (data that have a trend in the mean) is to look at the differences or "deltas" between successive data points i.e. the difference in the value of the series at times t and t-1 This statistical technique called "differencing" removes the long term trend in the mean of the data set, and exposes variation from one time period to the other. Figure 5.2 shows the result of "first differencing" for the typical winter daily load profile shown in Figure 5.1.

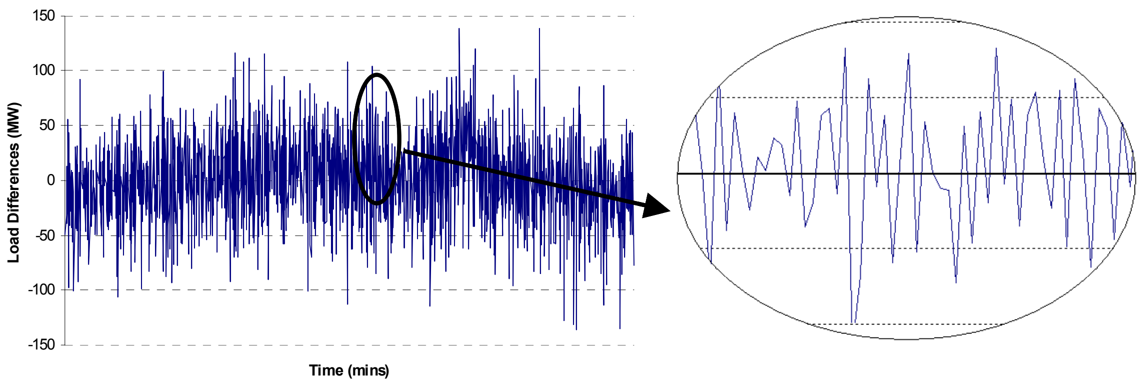


Figure 5.2 First Differences for a Typical Winter Daily load Profile and Expansion of a One-Hour Window

The resulting stationary series created by taking first differences of the non-stationary time series now has a mean of zero (or near zero) with the residuals or deltas varying in a "random" fashion about the mean (as shown in the one-hour window in Figure 5.2). Understanding the probability distribution of the load deltas is a very important part of describing the variation. A rational assumption (based on experience) is that the deltas are normally distributed about the mean. However, this assumption can be quickly checked by performing a normality test.

A normality test generates a normal probability plot and performs a hypothesis test to examine whether or not the observations follow a normal distribution. Figure 5.3 shows the results of a normality test for the load deltas in Figure 5.2.

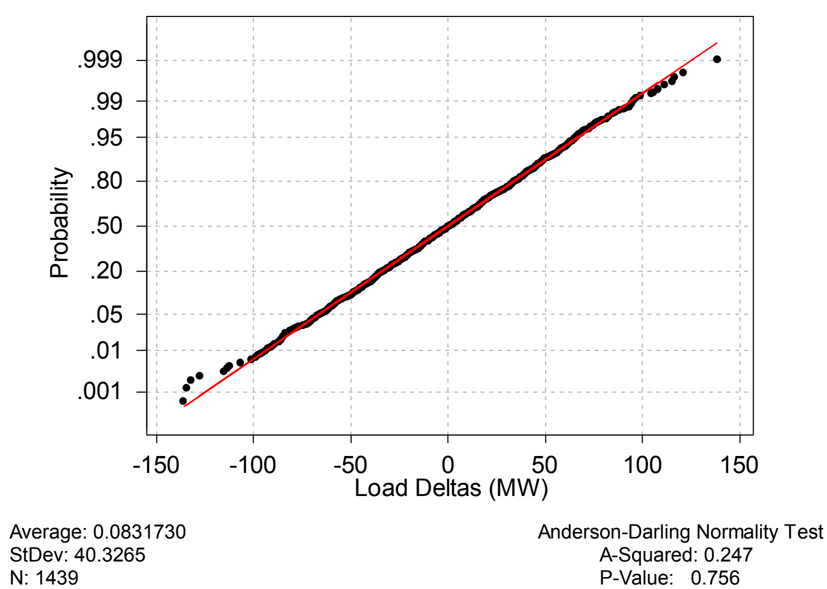


Figure 5.3 Results of Normality Test on Load Deltas for a Typical Winter Daily Load Profile

On the probability plot in Figure 5.3, the cumulative distribution function (cdf) for a normal population (red line) appears to be a good fit for the cdf of the observed load deltas. The hypothesis test gives more confirmation.

The null and alternative hypotheses are

H_0: load deltas follow a normal distribution

H_1: load deltas do not follow a normal distribution

At significance level $\alpha = .05$ (i.e. 5% chance of rejecting a true null hypothesis)

If P-value < .05, reject H_0 (deltas not normal)

If P-value ≥ .05, do not reject H_0 (deltas are normal)

From the results of the Anderson-Darling normality test in Figure 5.3, P-value = .756, one can conclude that the distribution of load deltas for these 24 hours of 1-minute data are consistent with a normal distribution. A similar exercise with the wind deltas over a one-day time frame shows that they are not necessarily normally distributed, but the load-wind deltas are approximately normal. With a longer series of data that has lower resolution, there are factors, such as diurnal and seasonal periodicity, and data integration that could cause the normality test to fail.

This chapter will examine and present the results of a statistical variability analysis of load, wind and combined load-wind with particular emphasis on the first differences (deltas) of the time series. The basic tools of descriptive statistics, mean and standard deviation will be used to assess and characterize the variability.

5.2 Long Term Variability

Over the course of a year, the load and wind vary significantly in magnitude and relative persistence. Figure 5.4 to Figure 5.7 show time series plots for 2020 load and 10,000 MW of wind[4] for the four representative seasonal months, January, April, July and October. (Plots of the other months are given in Appendix A). Each plot shows the time series for monthly load and wind on separate axes. The left axis gives the load magnitude and the right axis gives the wind magnitude. On each plot, the higher series (pink) is the load and the lower series (blue) is the wind. Because they are on different axes, the relative height of load and wind on each plot is meaningless, but it is revealing to compare the coincident phase relationship of the two series. It is also interesting to compare the load and wind magnitude across the four plots.

These plots (along with the plots of the other 8 months) show a clear seasonal variation in load and wind over the year. Load is consistently higher in the summer and winter months than the fall and spring months, as expected, and has a clear diurnal cycle. In general, wind seems to be consistently lower in the summer and higher in the winter, with periods of high and low output in the fall and spring. Over

[4] As explained in Appendix B, 10,000 MW of includes all the wind project groups plus the existing/signed wind. The wind variation across the year is expected to be similar for 5000, 6000 and 8000 MW of wind. As agreed upon with the Requesting Parties, 2020 load is a scaled up version of 2005 load so it has exactly the same shape and similar variation characteristics.

the course of a month, the wind has no obvious periodicity, but exhibits a fair amount of persistence, i.e. when it is high, it tends to stay high for a while.

While there is no observable, consistent diurnal correlation between load and wind, the time series plots do suggest some seasonal correlation. During the winter months when load is high, wind output is also high (positive correlation), which will tend to boost the capacity value of wind, as was discussed in Chapter 4, *Capacity Value Analysis*. However, during the summer months when load is also high, wind output is low, which reduces the capacity value of wind (negative correlation).

Within each month there is also a weekly pattern where load is lower on the weekend, and higher on weekdays.

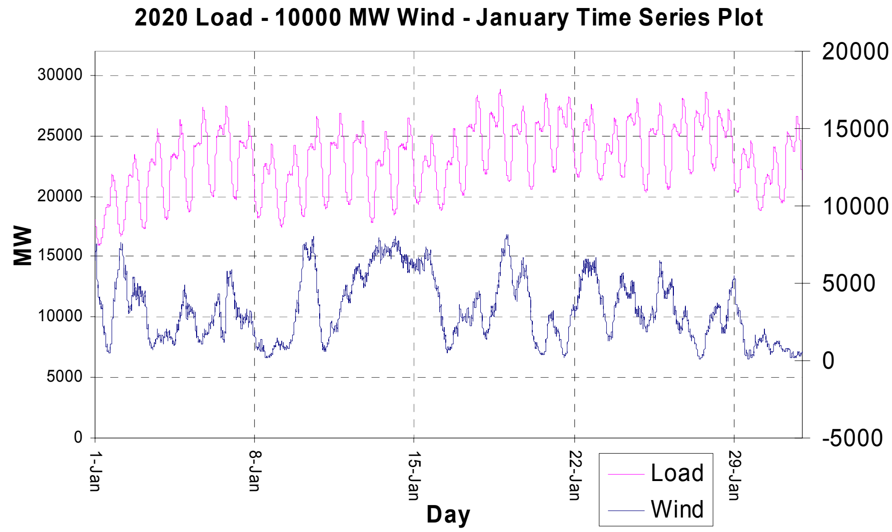


Figure 5.4 January (Winter) Time Series Plots for 2020 load and 10,000 MW of Wind

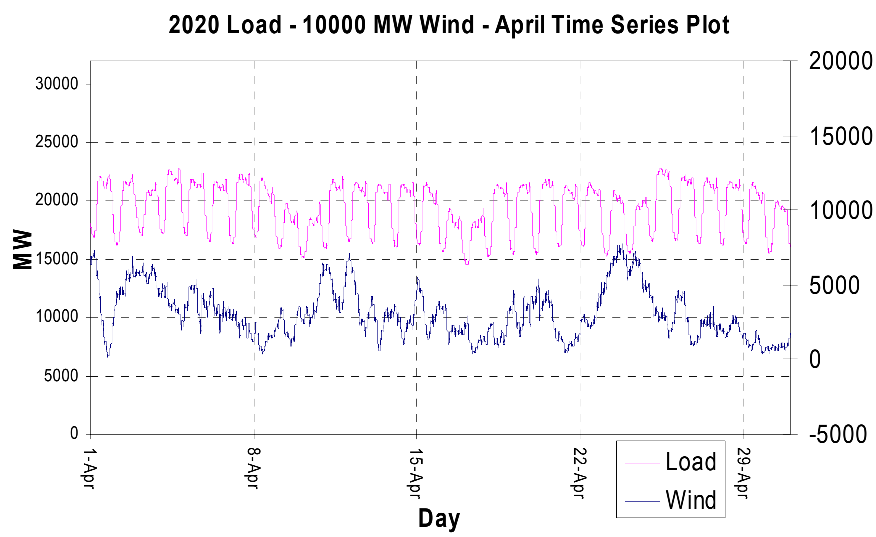


Figure 5.5 April (Spring) Time Series Plots for 2020 load and 10,000 MW of Wind

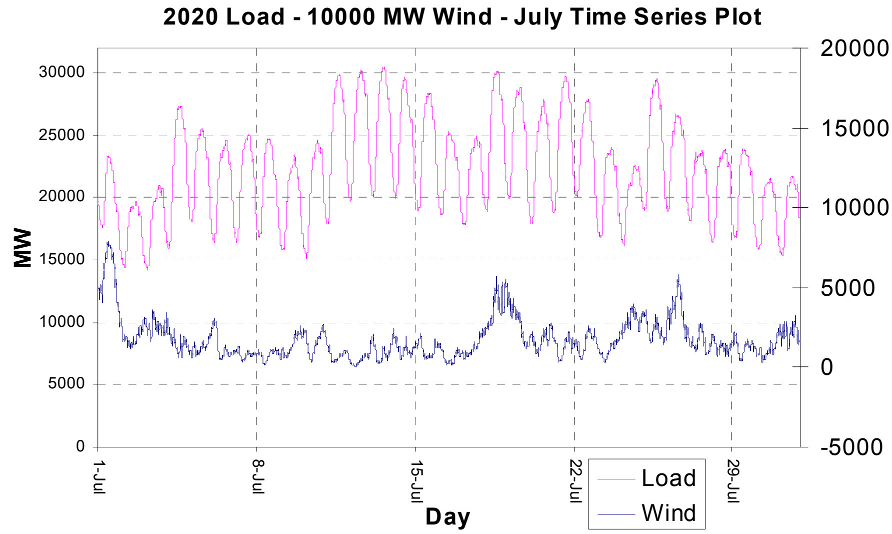


Figure 5.6 July (Summer) Time Series Plots for 2020 load and 10,000 MW of Wind

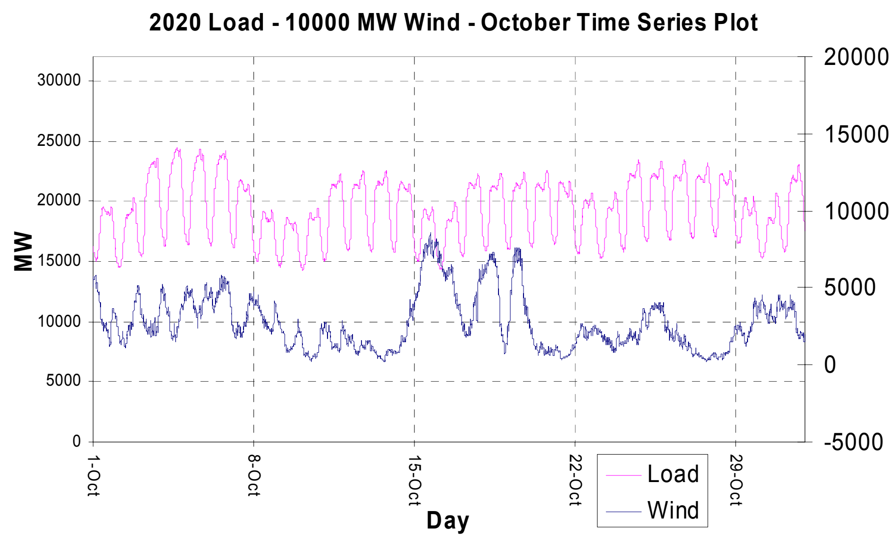


Figure 5.7 October (Fall) Time Series Plots for 2020 load and 10,000 MW of wind

The very long-term (daily, weekly, seasonal) variation in load and wind, while important for planning purposes, does not directly drive operation decisions concerning scheduling, dispatch/load-following, and regulation. These decisions are impacted by the behavior of load and wind in the multi-hourly, hourly and inter-hourly (minute-minute) time frames. The next section will examine the details of three-hour, hourly, ten-minute and minute-to-minute load variation, wind variation and combined load-wind variation. Insights gleaned from this analysis will help determine the operational impact of various wind scenarios on the Ontario bulk power system.

5.3 Hourly and Multi-Hourly Variability

In the hourly and multi-hourly time frames, variations in load and wind directly impact operations relating to unit commitment, generation scheduling and ramping requirements. In the Ontario electricity market, generation dispatch is performed every five minutes in response to the changing load and generation mix at the time. Wind generation, being low in the generation stack, is not dispatchable and would tend to either increase or decrease the load variation. In order to understand the additional operational burden imposed by wind, it is necessary to study the variation in the combined "Load-Wind" series and compare this to the variation in the "Load" series that the system is currently configured to operate under. For completeness and insight, the variation in the "Wind" series alone is also studied in some time frames. The implications of the results for operation are discussed in the *Operational Impact – Scheduling and Ramping* subsection.

5.3.1 Daily Load Profiles

Figure 5.8 shows the daily load profiles for the peak summer and winter days in 2005 (i.e. before scaling to projected future levels).

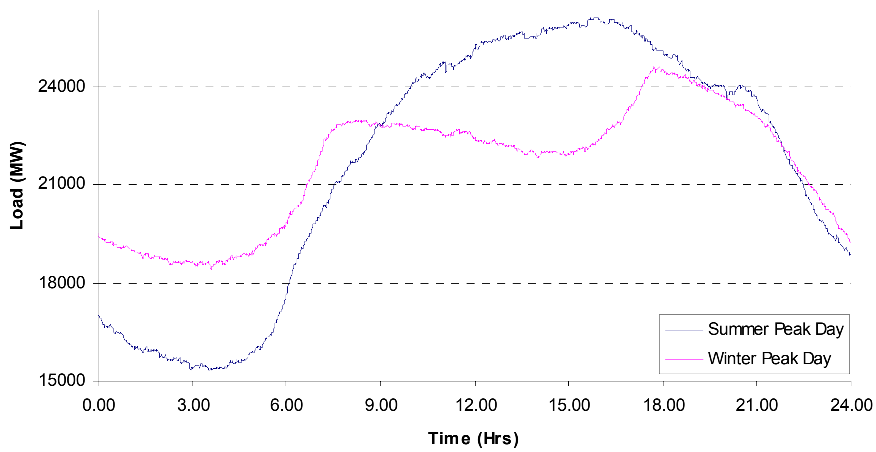


Figure 5.8 Daily Load Profiles for Peak Summer and Winter Days, 2005

The plots are based on the 1-minute resolution data provided by the IESO. These peak days are typical of the load shapes observed during the summer and winter on the Ontario system. The summer and winter load shapes show three distinct windows of variability that merit increased scrutiny because of how the load (and the wind) are behaving during that time.

- **Morning Load Rise** – During the summer mornings from about 6 – 10 AM the summer load profile shows a rapid increase in load. The winter profile shows a less pronounced increase from about 6 – 8 AM. The morning load rise period is interesting from an operations point of view because (as discussed later in Section 5.3.4) the wind tends to drop in the mornings when the load is rising.
- **Winter Afternoon Load Rise** – During the winter afternoons from about 4 – 6 PM, the winter load profile shows a rapid load increase toward the early

evening peak. As with the morning rise, this window may be interesting if the wind is also changing and potentially aggravating the net load-wind variability.

- **Evening Load Decline** – During the evenings from about 9 PM – 12 AM both summer and winter profiles show a characteristic decrease in load toward a minimum value in the early morning period. This evening decline period may be operationally challenging when wind variability is high, system load is low, and balance-of-generation has limited ramping capability.

The next section examines the statistical variability of the load from hour to hour over an entire year and also within the three challenging daily load periods identified above. In a later section, the multi-hour variability will be examined.

5.3.2 Hourly Load Variability

The basis for examining the hourly load variability is the 2005 one-minute resolution data provided by the IESO (monthly time series plots of the data are included in Appendix A). The load was scaled up to the projected 2009 and 2020 levels by applying appropriate scaling factors (as discussed in Appendix B), then one-hour data was produced by averaging the load over 60 minutes. The 2009 and 2020 load series were de-trended by taking "first differences" to produce load deltas -- which are the differences between the load in successive hours.

To produce a probability distribution of hourly load deltas for 2009 and 2020, the 8,759 data points were sorted into 200 MW bins and plotted on a histogram. Figure 5.9 shows the probability distribution of the 2020 one-hour load deltas.

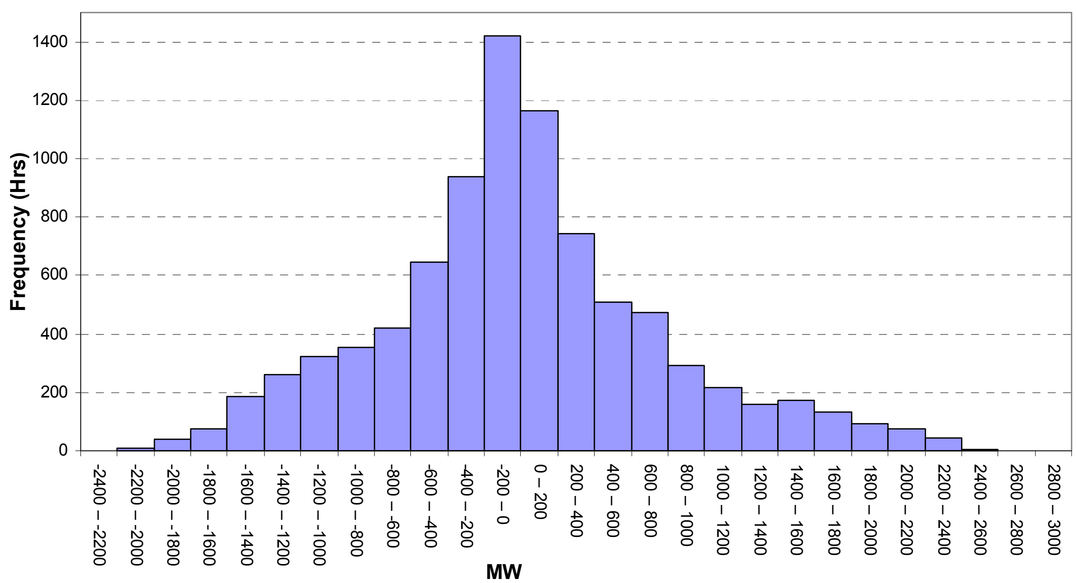


Figure 5.9 Distribution of Hourly Changes for Year 2020 Load

The distribution of the 2009 one-hour load deltas (not shown) is similar to the 2020 load deltas, as expected, since they are both derived from the 2005 load data. In both distributions, the load deltas show significant spread around the mean and a slight right skew. For the 2020 load delta distribution, there are 12 hours (.14%) where the load drops by at least 2,000 MW/hr compared to 126 hours (1.4%) where the load rises by at least 2,000 MW/hr. However the majority of load changes (95%) are less then ± 1600 MW/hr. Table 5.1 summarizes the descriptive statistics for one-hour changes in the two load series.

Table 5.1 Descriptive Statistics for Year 2009 and 2020 One-Hour Load Changes

	2009 Load	2020 Load
Mean	0	0
Std Dev (σ)	689	780
Min Delta	-2029	-2298
Max Delta	2484	2813
Points ≥ 3σ (-/+)	0 / 12	0 / 12
Points ≥ 4σ (-/+)	0 / 0	0 / 0

If the load deltas are normally distributed, it is expected that 99.7% of the 2020 load deltas will be within 3 standard deviations (σ) of the mean. Given that the observed standard deviation is 780, this would translate to .3% or about 26 hours when the 2020 hourly load change is expected to be more than ± 2,340 MW. In the observed data, there were only 12 instances (.14%) when the 2020 load change was greater than ± 2,340. These 12 hours (all when the load is rising) would tend to present the greatest hour-to-hour operational challenge during the year.

5.3.3 Hourly Wind Variability

The aggregate wind variability is a result of the variability of the individual wind groups. As discussed in Chapter 3, *Wind Production profiles*, AWS Truewind provided one year of ten-minute sampled wind data for ten prospective wind groups and a group of existing/signed wind projects. The wind groups varied in size from 143 MW to 1752 MW and exhibited different variability characteristics based on the location and size of the wind projects/sites comprising the group.

Monthly time series for four aggregate wind scenarios (5,000 MW, 6,000 MW, 8,000 MW and 10,000 MW) were produced by combining and scaling the wind group data and the existing/signed wind projects as explained in Appendix B. The monthly time series for the 10,000 MW wind penetration scenario are included in Appendix A. When the individual wind groups were combined to create aggregate wind penetration scenarios, it was observed that the variability of the aggregate wind was somewhat reduced due to group diversity. This effect will be further explored in Section 5.6, *Sudden Weather Change Analysis*.

Unlike the load, the wind output has no clear, *consistent* periodicity (although on average some diurnal cycling is observable), but instead tends to vary almost "randomly" over the course of a day. Figure 5.10 shows the daily wind generation for the 10,000 MW scenario during the peak summer and winter days in 2005, (the same days for which the load profiles were shown in Figure 5.8).

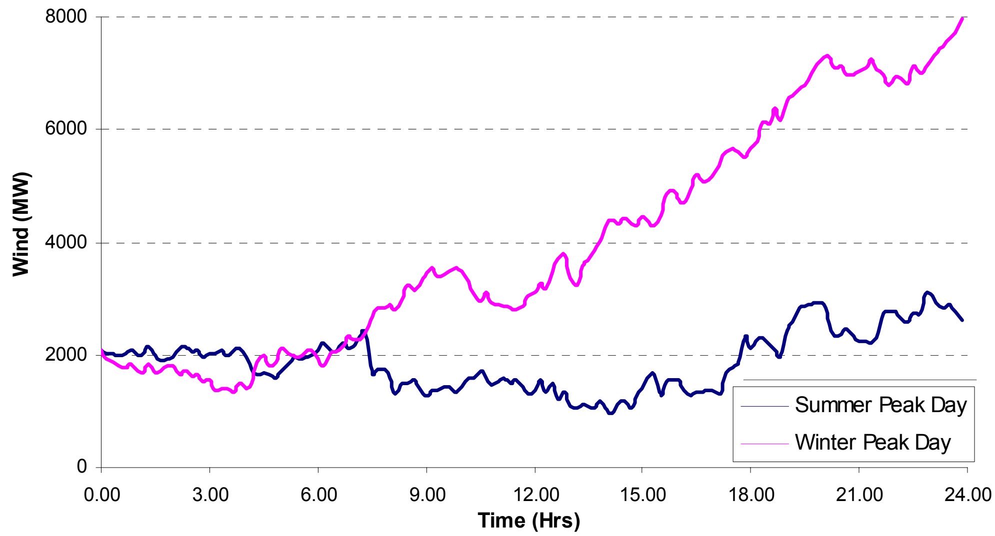


Figure 5.10 Daily Wind Generation (10,000 MW) for Peak Summer and Winter Days in Year 2005

The plots show that the wind generation on the peak summer day in 2005 is consistently low whereas output increases steadily on the peak winter day. While other summer and winter days do not necessarily have the same pattern, there is a general tendency for wind to persist more in winter than summer (see Section 5.3.4, *Load and wind Coincidence*).

Hourly wind data for the four wind penetration levels as well as the 1310 MW group were derived from the ten-minute wind data by averaging the wind output over a 60-minute period. The monthly wind series for each wind scenario were de-trended by taking "first differences" to produce a series of wind hourly changes.

Sorting the 8,759 data points for each scenario into 200 MW bins and plotting them on a histogram produced a probability distribution of hourly wind deltas. Figure 5.11 shows the one-hour delta distribution for the 10,000 MW Wind scenario.

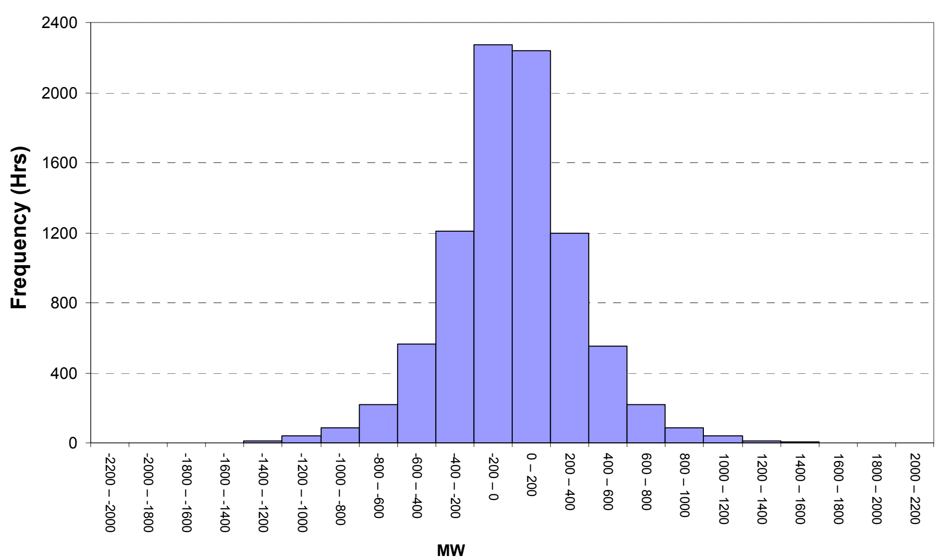


Figure 5.11 Distribution of Hourly Changes for 10,000 MW of Wind

The probability distribution for the other 2020 wind levels (5,000 MW, 6,000 MW, and 8,000 MW) are similar to the 10,000 MW scenario since they are composed of basically the same groups with different scaling factors. The wind delta distribution for the 2009 wind level (1,310 MW) is likely to be different from the other scenarios for obvious reasons. The descriptive statistics for one-hour changes for the five wind penetration scenarios are summarized in Table 5.2.

Table 5.2 Summary of Hourly Wind Variability for the Five Wind Generation Scenarios

	1310 MW Wind	5000 MW Wind	6000 MW Wind	8000 MW Wind	10000 MW Wind
Mean	0	0	0	-1	-1
Std Dev (σ)	59	186	223	272	342
Min Delta	-397	-1028	-1291	-1404	-1769
Max Delta	570	1290	1428	1634	2035
Points ≥ 3σ (-/+)	62 / 51	57 / 58	47 / 56	43 / 50	46 / 54
Points ≥ 4σ (-/+)	15 / 14	15 / 9	8 / 14	4 / 9	4 / 9
Points ≥ 5σ (-/+)	3 / 2	1 / 1	1 / 2	2 / 1	2 / 1
Points ≥ 6σ (-/+)	1 / 2	0 / 1	0 / 1	0 / 1	0 / 0

As the level of wind output increases, the variability (as measured by the standard deviation) also increases, from 59 with the existing/signed wind, to 186 with 5,000 MW of wind, and eventually 342 with 10,000 MW of wind. If the wind deltas are normally distributed, it is expected that 99.7% of the wind deltas will be within 3 standard deviations (σ) of the mean. For 10,000 MW, this would translate to 26 hours when the hourly wind change is expected to be greater than ± 1026 MW. In the observed data for the 10,000 MW scenario, there were actually 100 hourly periods (1.1%) when the wind change was greater than ±3σ. Recall that for the load alone, there were only 12 hourly periods when the one-hour load change was greater than ± 3σ. However, note that the load σ of 780 is more than twice the 10,000 MW wind σ.

For all the penetration scenarios, on a relative basis, the wind exhibits more central tendency (less spread) than the load. Even for the highest wind penetration level (10,000 MW), the maximum one-hour change in wind output, 2,035 MW, is less than the maximum one-hour change in load alone, 2,813 MW (from Table 5.1).

5.3.4 Load and Wind Coincidence

The key to determining the impact of wind penetration on power system operation is the variability of the combined load and wind. Figure 5.12 and Figure 5.13 show the *average* daily load profiles for 2020 load and 10,000 MW of wind during representative months in the four seasons.

The load and wind profiles are plotted together so that the *average* phase relationship between load and wind in the various seasons can be observed. Note, however, that the two curves are plotted on different y-axes (load on the left and wind on the right) so that the variation in wind can be more clearly shown. As such, the relative magnitudes of load and wind curves on a plot should not be compared.

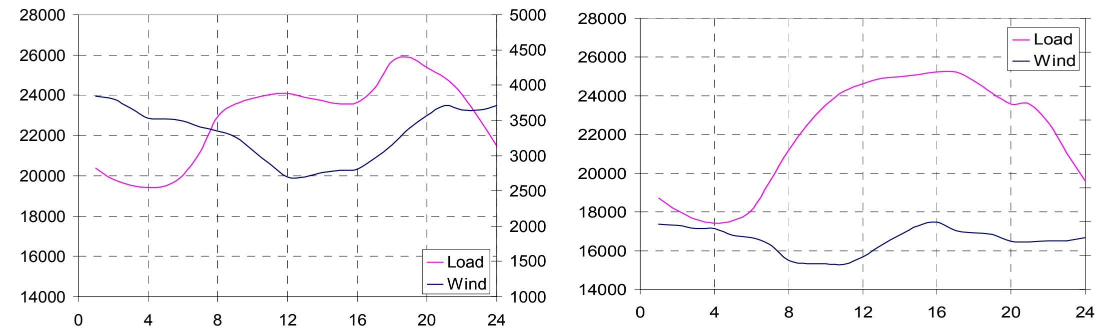


Figure 5.12 January and July Average Daily Profiles for 2020 Load and 10,000 MW of Wind

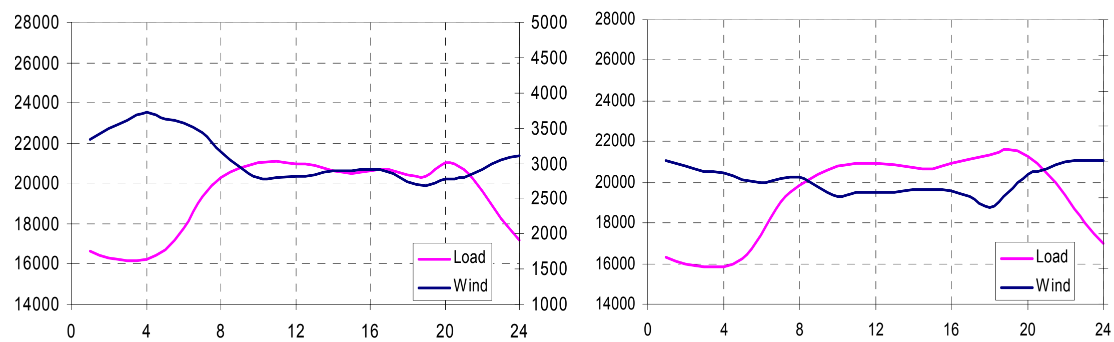


Figure 5.13 April and October Average Daily Profiles for 2020 Load and 10,000 MW of Wind

During the winter months (typified by January), the wind *on average* tends to peak around midnight, steadily decrease during the morning hours to a daily low around midday and then ramp up in the evening. When compared to the *average* daily load cycle, it is evident that the winter phase relationship can lead to operational challenges, especially during the late evening and early morning periods when the load is low or decreasing and the wind is changing rapidly. During the winter afternoon load rise period, net variability may be an issue, but the wind seems to be generally helping during these hours. The winter morning load rise period also may present operational difficulties, but less so than the summer morning load rise period, which is almost twice as long.

During the summer months (typified by July), the wind *on average* is generally flat (and low), but tends to decrease slowly during the morning hours to a mid-morning low, and rise slowly in the early afternoon. When compared to the *average* daily load cycle, it can be seen that the greatest summer operational challenge is during the summer morning load rise period, when the load is increasing steeply while the wind is decreasing.

During the spring and fall months (typified by April and October), the wind is generally flat, (except for a pronounced rise and fall in the early spring morning), with an output level between the summer and winter magnitudes. The most significant operational challenge may be in the early spring morning when the load is low and the wind is varying. Late evening periods where the load is declining rapidly and wind is slowly rising or constant may also be interesting.

Some of the seasonal characteristics of load and wind described above were used to select "interesting periods" for minute-to-minute analysis in Section 5.5.

In order to determine the operational requirements in the hour-to-hour timeframe and the impact on generation scheduling and unit commitment, the variability of the combined load and wind time series, called "load-wind" is examined in the next section.

5.3.5 Hourly Load-Wind Variability

Load-wind monthly time series data were produced for each load and wind scenario by subtracting the wind time series from the appropriate load time series. The resulting combined load-wind series were de-trended by taking "first differences" to produce load-wind deltas for each scenario.

Sorting the 8,759 data points for each scenario into 300 MW bins and plotting them on a histogram produced the probability distribution of hourly load-wind deltas. Figure 5.14 shows the probability distribution of hourly changes for the year 2020 load with 10,000 MW of wind. The hourly changes in year 2020 load alone are included on the same plot for comparison. The distribution of hourly changes for 2020 load with 5,000, 6,000, and 8,000 MW of wind, and 2009 load with 1,310 MW of wind are plotted in Appendix A.

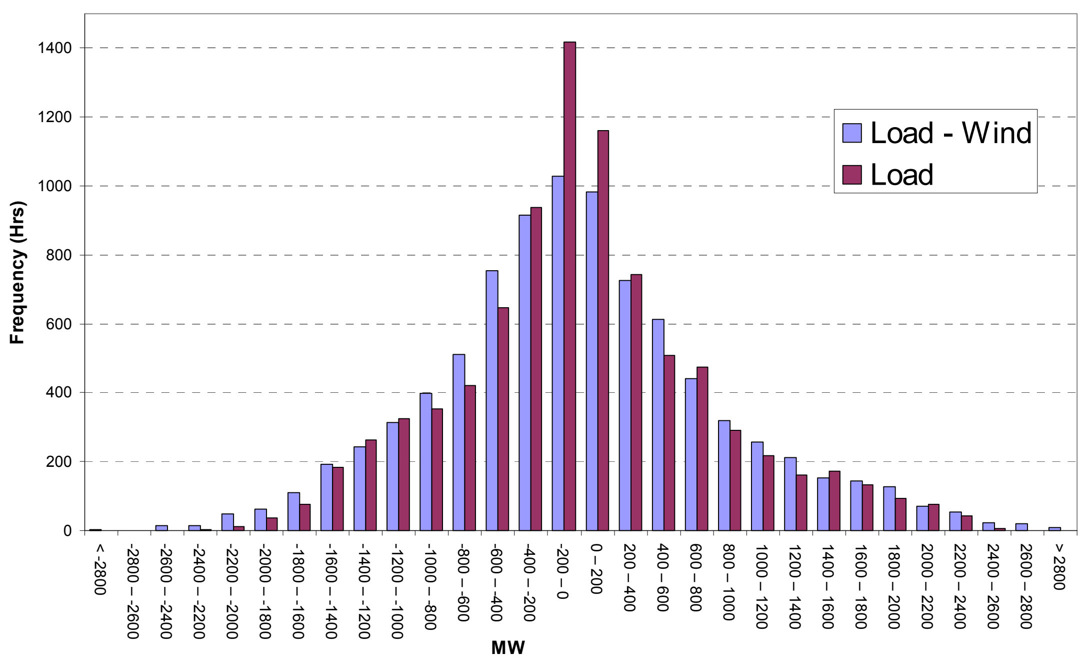


Figure 5.14 Distribution of Hourly Changes for Year 2020 Load and 10,000 MW of Wind

The distribution plots show that with the addition of wind variability to the load, the combined load-wind distribution has less central tendency than load alone. The load-wind bars around the mean are lower than the load alone, and the bars on the tails of the distribution are higher. This is consistent with the expectation that the standard deviation of load-wind changes would be higher than load alone, and there would be more "extreme values," i.e. hourly changes greater than $\pm 3\sigma$.

Table 5.3 summarizes descriptive statistics for hourly load-wind changes for the five load and wind scenarios. The statistics for load alone are included for comparison.

Table 5.3 Summary of Hourly Variability for the Five Load and Wind Penetration Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	0	0	0	1	1	1	1
Std Dev (σ)	689	690	780	803	817	836	864
Min Delta	-2029	-2101	-2298	-2398	-2666	-2730	-2990
Max Delta	2484	2511	2813	2857	2853	3414	3780
Points $\geq 3\sigma$ (-/+)	0 / 12	1 / 14	0 / 12	0 / 17	3 / 21	3 / 24	3 / 28
Points $\geq 4\sigma$ (-/+)	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0	0 / 1	0 / 1

Across the board, there is a modest increase in variability (as measured by σ) as the amount of wind generation increases. For year 2020, the standard deviation of the load variability alone (no wind) is 780. This σ is increased by 23 (or 2.9%) with 5,000 MW of wind and by 84 (or 10.8%) with 10,000 MW of wind. For year 2009, 1310 MW of wind increases the σ by only .15%. If the load-wind deltas are normally distributed, it is expected that 99.7% of the load-wind deltas would be less than $\pm$ 2,592. This would translate to an expectation of .3% or 26 hours of 'extreme hourly load-wind changes. For the "2020 load with 10,000 MW of wind" scenario in Table 5.3, there are 31 hourly periods (.35%) of extreme load changes (deltas greater than ± 3 *load-wind* σ), which is a 19 hour increase over the 2020 load-alone case. The single largest hourly rise for 2020 load with 10,000 MW of wind is 3,780 MW (a 967 MW increase over load-alone) and the single largest hourly decline is –2,990 MW (a 692 MW increase).

In year 2009 with 1,310 MW of wind, there are three additional hours where the load changes by at least 3σ. The maximum load rise increases by 1% and the maximum load drop increases by 3.5%.

5.3.6 Hourly Variability During Challenging Daily Periods

Based on the typical daily load shape, several periods of rapid load change were identified as especially challenging for daily operation. These periods were described previously in Section 5.3.1 as summer morning load rise, winter afternoon load rise, and evening load decline. During these periods generation may be required to undergo sustained ramping over several hours to supply the net load. Examination of the hour-to-hour and multi-hour changes during these periods will help determine requirements for day-ahead hourly scheduling, and the ramping capability needed.

5.3.6.1 Summer Morning Load Rise Period

The summer morning load rise is especially challenging because the load rise is quite steep and the wind tends to be at its lowest level during the high rise period (as shown in Figure 5.12). This would serve to increase the hourly variability of combined load and wind. Figure 5.15 shows the hour-to-hour variability during the summer morning load rise period for combined 2020 load and 10,000 MW of wind. The data for the four-hour period from 6-10 AM for June to September were separated into 200 MW bins and plotted. The summer morning load rise hourly variability for the 5000 MW wind and year 2009 scenarios are shown in Appendix A.

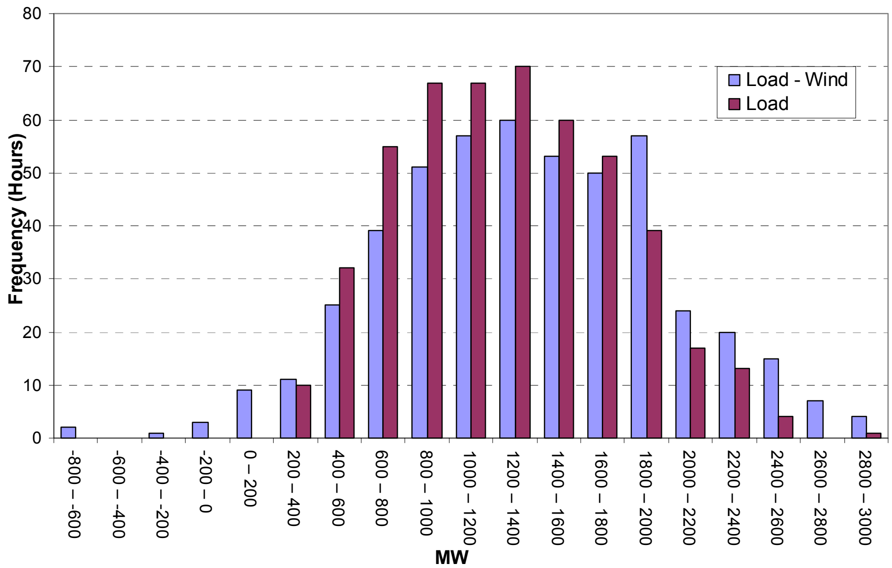


Figure 5.15 Summer Morning Load Rise Hourly Variability for Year 2020 Load and 10,000 MW of Wind

As expected, the distribution of load alone hourly changes is positive, (because load is rising), and is somewhat skewed to the right. During this operating period, large rates of load rise are not unexpected. In Figure 5.15, there are 35 hourly periods (7% of the morning rise hours) when the load rise rate is ≥ 2,000 MW/hr. With the addition of 10,000 MW of wind, the distribution of hourly load-wind deltas is spread over a much wider range, with 70 periods (14%) of net load-wind changes ≥ 2,000 MW/hr. In fact, the plot shows that for all load changes ≥ 1800 MW/hr, the addition of wind serves to increase the net load-wind variability, possibility adding to operational challenges.

Similarly, in the probability distribution for the year 2009 scenario (Appendix A) there are 12 periods (2% of the morning rise hours) when the load rise rate is ≥ 2,000 MW/hr. With the addition of 1,310 MW of wind, there are an additional 5 periods (3%) when combined load-wind rise rate exceeds 2000 MW/hr.

Table 5.4 summarizes descriptive statistics for hourly load-wind deltas (with load alone for comparison) during the summer morning load rise period, for the five combined load-wind scenarios.

Table 5.4 Summary of Summer Morning Load Rise Hourly Variability for Wind Penetration Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	1110	1111	1257	1273	1308	1340	1365
Std Dev (σ)	438	450	496	546	563	584	622
Min Delta	194	84	220	-454	-454	-486	-664
Max Delta	2484	2511	2813	2857	2853	2777	2920
Points ≥ ±3σ	1	1	0	1	1	1	2

As the wind penetration increases there is an expected increase in summer morning rise hourly net variability, as evidenced by a 25% increase in the standard deviation from the year 2020 no wind case to the 10,000 MW wind scenario. The maximum hourly change in 2020 with no wind is 2813 MW, increasing (by less than 2%) to 2,857 MW with 5,000 MW of wind, and (by less than 4%) to 2,920 MW with 10,000 MW of wind. At the highest wind penetration level, there are only 2 hours where the hourly change is greater than 3 times the net load-wind σ.

In year 2009, there is a modest increase in σ (2.7%) with 1,310 MW of wind and only a 1% increase in the maximum one-hour load rise.

5.3.6.2 Winter Afternoon Load Rise Period

As shown previously in Figure 5.12, the winter afternoon load rise tends to be less than the summer morning load rise and the wind is *generally* helping to reduce the net hour-to-hour variability during this period. Figure 5.16 shows the hour-to-hour variability during the winter afternoon load rise period for combined 2020 load and 10,000 MW of wind. The data for the two-hour period from 4-6 PM for November to February were separated into 200 MW bins and plotted. Appendix A shows the winter afternoon load rise hourly variability for the 500 MW wind and year 2009 scenarios.

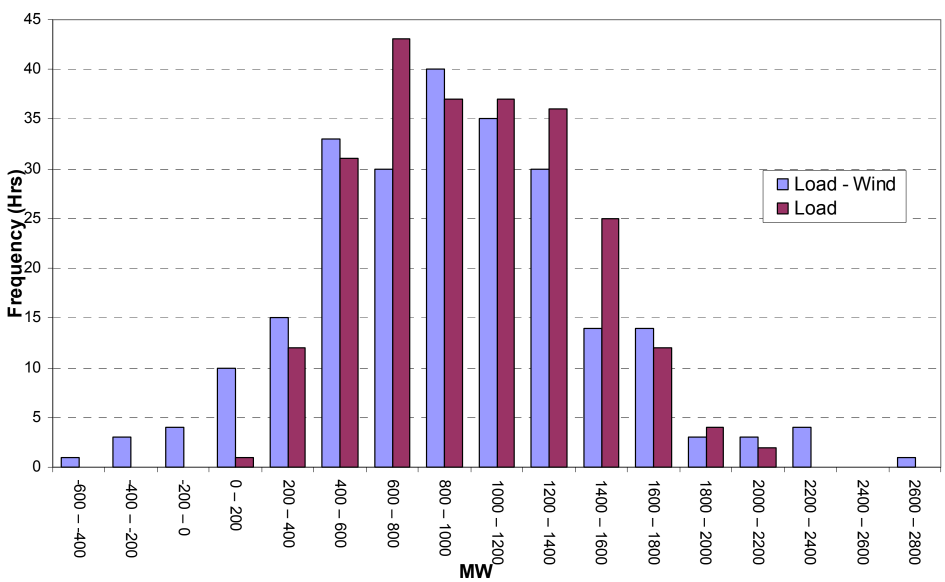


Figure 5.16 Winter Afternoon Load Rise Hourly Variability for Year 2020 Load and 10,000 MW Wind

During the winter afternoon load rise period, the hourly load changes are positive, (as expected), and slightly skewed to the right. In this case, there are 2 hours (or 1% of the winter afternoon load rise periods) when the load rise rate is greater than 2,000 MW/hr. With the addition of 10,000 MW of wind, there are only 8 hours (3%) when load changes ≥ 2,000 MW/hr -- compared with 70 hours for the summer morning load rise period.

Table 5.5 summarizes statistics for hourly load-wind deltas during the winter afternoon load rise period, for all five load and wind scenarios.

Table 5.5 Summary of Winter Afternoon Load Rise Hourly Variability for Wind Penetration Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	882	878	999	982	958	943	926
Std Dev (σ)	359	355	407	436	442	470	517
Min Delta	113	40	128	6	-38	-356	-570
Max Delta	1812	1785	2052	2096	2202	2358	2632
Points ≥ ±3σ	0	0	0	0	0	1	1

As Table 5.5 shows, for year 2020 there is a 27% increase in standard deviation from the no wind case to the 10,000 MW wind case. The maximum hourly change with no wind is 2,052 MW, increasing (by 2%) to 2,096 MW with 5,000 MW of wind and (by 28%) to 2,632 MW with 10,000 MW of wind. At the highest wind penetration level, there is one hour where the hourly change is greater than 3 (load-wind) σ.

For year 2009, as it happens, the addition of 1,310 MW of wind actually serves to *reduce* the net variability in this period. The standard deviation decreases by 1.1% and the maximum one-hour load change goes from 1,812 MW to 1,785 with wind.

5.3.6.3 Evening Load Decline Period

During the evenings, load tends to decline *on average* from about 9 PM to Midnight across the four seasons, as shown previously in Figure 5.13. During low load hours, systems are primarily run on base-load, non-dispatchable generation with limited maneuverability to counteract sudden changes in wind output. This can create operating challenges, especially when the load is low and wind is dropping. Figure 5.17 shows the hourly variability during the evening load decline period from June to September for 2020 load with 10,000 MW of wind. The evening load decline hourly variability for the 5,000 MW wind and year 2009 scenarios is shown in Appendix A.

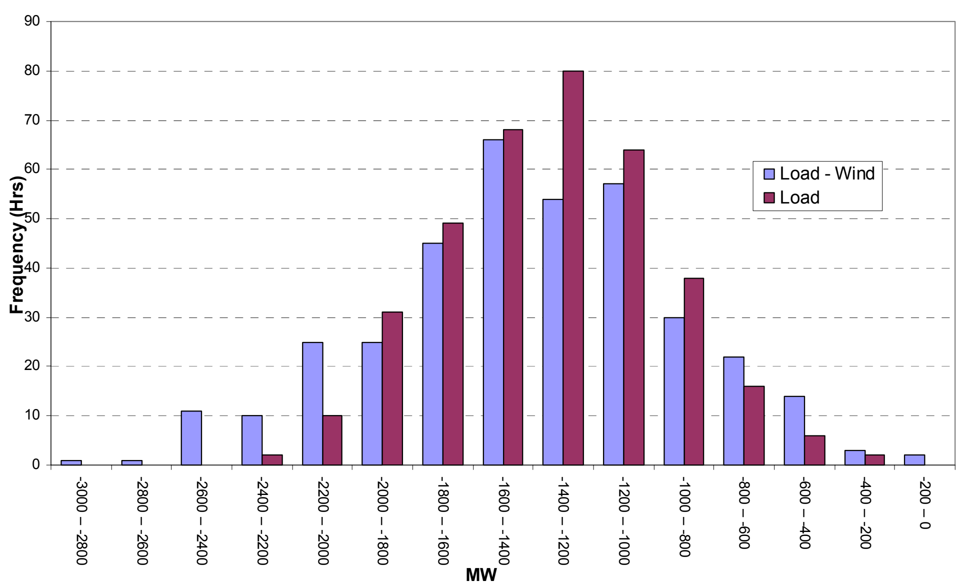


Figure 5.17 Evening Load Decline Hourly Variability for Year 2020 Load and 10,000 MW Wind

As expected, the hour-to-hour load changes in the evening load decline period are all negative and skewed to the left. For this 2020 scenario, there are 12 periods (3% of the evening decline hours) when the load *drops* by more than 2,000 MW/hr. With the addition of 10,000 MW of wind, there are 48 hours (or 13%) when net load-wind drops ≥ 2,000 MW/hr.

In year 2009 (see Appendix A) there are only 2 hours (less than 1%) when load drops exceed 2,000 MW/hr. With the addition of 1,310 MW of wind, there is only one additional hour when load drops ≥ 2,000 MW/hr.

Table 5.6 summarizes descriptive statistics for hourly load-wind deltas (with load alone for comparison) during the evening load decline period for all five load and wind scenarios.

Table 5.6 Summary of Evening Load Decline Hourly Variability for Wind Penetration Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	-1195	-1201	-1353	-1366	-1382	-1395	-1406
Std Dev (σ)	318	322	360	401	423	450	496
Min Delta	-2029	-2101	-2298	-2398	-2666	-2730	-2990
Max Delta	-266	-271	-301	-226	-203	-230	-70
Points ≥ ±3σ	0	0	0	0	1	0	1

The data in Table 5.6 shows that for year 2020, there is a 38% increase in the standard deviation of net load-wind with 10,000 MW of wind, over the load alone scenario. The minimum delta (or maximum load change in the negative direction) is 2,298 MW and the smallest one-hour drop is 301 MW. With increasing levels of wind penetration, the maximum one-hour load drop increases accordingly. For 5,000 MW of wind, the maximum one-hour drop is 2,398 MW (a 4% increase over load-alone) and for 10,000 MW of wind, the maximum one-hour drop is 2,990 MW (a 30% increase over load-alone).

For year 2009 with 1,310 MW of wind, the standard deviation of net load-wind is increased by only 1.3% over 2009 load-alone and the maximum load drop increases by 3.5%.

In all three daily load periods, summer morning rise, winter afternoon rise, and evening decline, the addition of various levels of wind generation tends to aggravate the net load-wind variability (except for odd the 2009 winter afternoon load rise period, with 1310 MW of wind). In general, with increasing wind penetration:

1. there is a uniform increase in standard deviation of net load-wind
2. the magnitude of the maximum one-hour change in net load-wind increases
3. the number of hours of load-wind changes ≥ ±3σ increases

The impact of these hour-to-hour changes on operations requirements during these daily periods is examined further in the *Operational Impact* subsection.

5.3.7 Multi-Hour Variability

During a diurnal cycle, load, wind or combined load and wind may undergo sustained periods of ramping (up or down), which may last several hours. The previous three sections have described and characterized some periods during the day when sustained multi-hour ramping may occur. These are the morning load rise period (4 hours), the winter afternoon load rise period (2 hours) and evening load decline period (3hours). In addition to these recognized challenging periods, there are other periods of interest during the year that require generators to either ramp up or ramp down over several hours. The three-hour ramping capability of generators is a key requirement for reliable operation during these periods. Consequently, this section examines the three-hour variability of combined load and wind over a year of operation to provide an indication of the multi-hour ramping requirement with various amounts of wind generation.

5.3.7.1 Three-Hour Load-Wind Variability

The one-hour load-wind series (from the earlier hourly variability analysis) were used to produce the three-hour deltas for each of the load and wind scenarios (2009 Load with 1,310 MW of wind, 2020 load with 5,000 MW, 6,000 MW, 8,000 MW and 10,000 MW of wind). Because of the length of the time period (3 hours) it is possible that a large delta could be missed if all three-hour differences are not considered. Therefore a moving window (or shifting) approach was used to calculate the three-hour differences. In this approach, three series of 3-hour deltas were computed from the one-hour data. The first series starts with the delta *t*3 - *t*0 (no-shift), the second starts with *t*4 - *t*3 (one-shift) and the third starts with *t*5 - *t*2 (two-shift). The variability of the three series of deltas is compared and the most variable is reported.

Figure 5.18 shows the probability distribution of three-hour changes for year 2020 load with 10,000 MW of wind, based on the “two-shift” delta series.

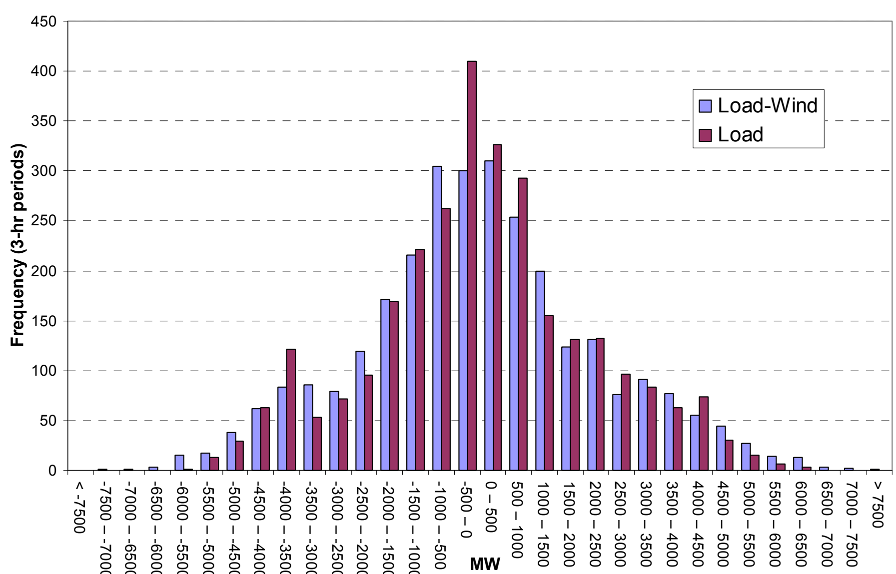


Figure 5.18 Distribution of Three-Hour Changes for Year 2020 Load and 10,000 MW of Wind

Much like the hourly distribution, the three-hour distribution has less central tendency (more spread) with the addition of 10,000 MW of wind. With load-alone, there are three 3-hour periods where the load changes by 6000 MW or more, but with 10,000 MW of wind, there are 24 such periods.

Table 5.10 summarizes descriptive statistics for three-hour load-wind changes for the five load and wind scenarios. The data is based on the "two-shift" delta series, which has the highest variability. Statistics for load alone are included for comparison.

Table 5.7 Summary of Three-hour Variability for the Five Load and Wind Penetration Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	1	2	2	2	2	2	3
Std Dev (σ)	1882	1882	2131	2179	2214	2252	2310
Min Delta	-4879	-4997	-5526	-6012	-6539	-6904	-7339
Max Delta	5725	5857	6484	6838	6919	7023	7586
Points $\geq 3\sigma$ (-/+)	0 / 1	0 / 1	0 / 1	0 / 2	0 / 2	2 / 3	2 / 3

For the year 2020 scenarios, there is modest increase in variability (as measured by σ) as the amount of wind generation increases. The standard deviation (σ) of the net load variability, (2131 with no wind), is increased by 48 (or 2.3%) with 5,000 MW of wind and by 179 (or 8.4%) with 10,000 MW of wind. With 10,000 MW of wind, there are 5 three-hour periods (.17%) where the load changes by at least 3σ, compared to one 3-hour period for the load-alone case. The single largest three-hour rise with 10,000 MW of wind is 7586 MW (an 1,102 MW increase over load-alone) and the single largest three-hour decline is –7,339 MW (an 1,813 MW increase over load-alone).

For the year 2009 scenario, 1,310 MW of wind has no appreciable impact on σ, and there are no additional extreme load changes ($\geq 3\sigma$). The maximum load rise increases by 2.3% and the maximum load drop increases by 2.4%.

The operational impacts of one-hour changes and multi-hour changes on generation scheduling and ramping requirements are further discussed in the next section.

5.3.8 Operational Impact – Scheduling and Ramping

The statistical variability of net load in the hour-to-hour and multi-hour time frames impacts day-ahead generation scheduling and unit commitment decisions. Based on the diurnal load cycle, units are scheduled one-day ahead to supply the anticipated load and meet the ramping requirements. As the load cycles through its daily profile, there are certain periods where generation may have to ramp over multiple hours, so the generation mix is critical to secure and stable operation of the power system. The daily profiles in Figure 5.12 and Figure 5.13, and operating experience suggests that if units are capable of three-hour sustained ramping, this may be enough capability to handle the worse periods during the year. However, the introduction of various amounts of wind may change the net load profile enough to impact hourly scheduling and increase the ramping requirement for generators in the multi-hourly time frame.

Table 5.8 characterizes the operational impact of various amounts of wind using 3σ as the metric. Under normal operating conditions, assuming that the load deltas are normally distributed, 99.73% of the hourly load variation will be within 3σ of the mean, i.e. within ±2,067 MW for the year 2009 scenario and within ±2,343 MW for the year 2020 scenarios. With 5,000 MW of wind in year 2020, the 3σ metric increases by 3% to ±2,409 MW, and with 10,000 MW of wind, the 3σ metric increases by 10% to ±2,592 MW. For year 2009, the increase in σ is only .2%. From an hourly scheduling point of view, even 10,000 MW of wind would not push the envelope much further beyond the current operating point. However, the amount and magnitudes of *extreme* one-hour net load changes are significantly greater with the wind.

Table 5.8 Summary of One-Hour Operational Impacts

Case	σ_{Load} (1hour) **(MW)**	$\sigma_{Load\text{-}Wind}$ (1hour) **(MW)**	$3\sigma_{Load}$ (1hour) **(MW)**	$3\sigma_{Load\text{-}Wind}$ (1hour) **(MW)**	3σ % Increase
2009 Load w/ 1,310 MW	689	690	2067	2070	0.2%
2020 Load w/ 5,000 MW	781	803	2343	2409	3%
2020 Load w/ 6,000 MW	781	817	2343	2451	5%
2020 Load w/ 8,000 MW	781	836	2343	2508	7%
2020 Load w/ 10,000 MW	781	864	2343	2592	10%

As shown earlier in Table 5.3, the maximum one-hour rise increases from 2,813 MW for load-alone to 3,780 MW or 34% with 10,000 MW of wind; and the maximum one hour drop increases from 2,298 MW for load-alone to 2,990 MW or 30% with 10,000 MW of wind. For 5,000 MW of wind in year 2020, the changes are only 1.5% and 4% respectively and for the year 2009 scenario, the changes are 1% and 3.5%. This data indicates that with large amounts of wind, much more one-hour ramping capability is needed for secure operation. In fact, with 10,000 MW of wind, there are 177 hours during the year when the net load *rises* ≥ 2,000 MW/hr, which is 51 hours more than load-alone (a 40% increase). Of these 177 hours, 70 occur during the summer morning load rise period. At the same level of wind penetration, there are 79 hours when the net load *drops* ≥ 2,000 MW/hr, which is 67 hours more than load-alone (a 558% increase). Of these 79 hours, 48 occur during the evening load decline periods.

Clearly the longest sustained ramping (up and down) occurs during the summer morning load rise and evening load decline periods. During these periods, (and others) the units may need to ramp continually over three or more hours. Table 5.9 characterizes the operational impact of various amounts of wind in the three-hour time frame.

Table 5.9 Summary of Three-Hour Operational Impacts

Case	σ_{Load} (3hour) **(MW)**	$\sigma_{Load\text{-}Wind}$ (3hour) **(MW)**	Max. Negative Load-alone Delta **(MW)**	Max. Positive Load-alone Delta **(MW)**	Max. Negative Load-Wind Delta **(MW)**	Max. Positive Load-Wind Delta **(MW)**	σ % Increase
2009 Load w/ 1310 MW	1882	1882	-4879	5725	-4997	5857	0.1%
2020 Load w/ 5,000 MW	2131	2179	-5526	6484	-6012	6838	2.2%
2020 Load w/ 6,000 MW	2131	2214	-5526	6484	-6539	6919	3.9%
2020 Load w/ 8,000 MW	2131	2254	-5526	6484	-6904	7023	5.7%
2020 Load w/ 10,000 MW	2131	2310	-5526	6484	-7339	7586	8.4%

The data shows that the increase in σ for all scenarios is relatively small, which means that the overall spread of three-hour changes is similar with and without wind. However, as in the case of hourly variation, the magnitude and number of the *extreme* changes are greater with wind, which means that more three-hour ramping capability is needed with wind. For the year 2020 with 10,000 MW of wind scenario, the maximum positive delta increases from 6,484 MW to 7,586 MW or 17% and the maximum negative deltas increases from 5,526 MW to 7,339 MW or 33%.

For the load-wind scenarios, Figure 5.19 shows the number of times (or 3-hour periods) that positive three-hour load changes (positive deltas) exceed or equal a MW threshold. Figure 5.20 shows the same data for negative three-hour load changes (negative deltas).

The plots clearly illustrate the fact that units will have to undergo sustained three-hour ramping more often, and ramp further with the addition of various amounts of wind. For example, for year 2020 load with 5,000 MW of wind, the number of times the 3-hour net load increases by 5,200 MW or more is about 30, compared with about 20 times for the no-wind (load-alone) scenario. With 10,000 MW of wind, the net load positive changes exceed 5,200 MW approximately 50 times. On the other hand, net load drops (or negative deltas) exceed 5,200 MW about 15 times with 5,000 MW of wind, approximately 30 times with 10,000 MW of wind, and about 5 times with no wind.

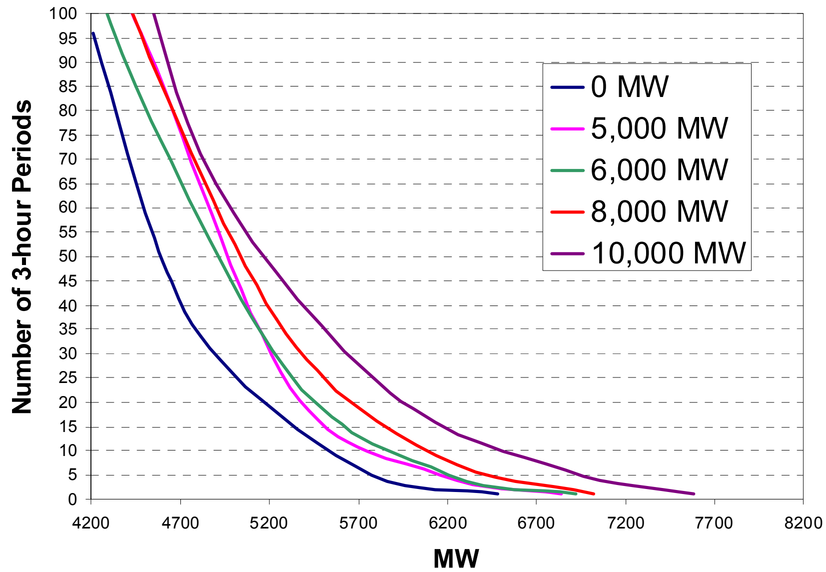


Figure 5.19 Number of Times 3-hour Load Rises Exceed a MW Threshold for Load-Wind Scenarios

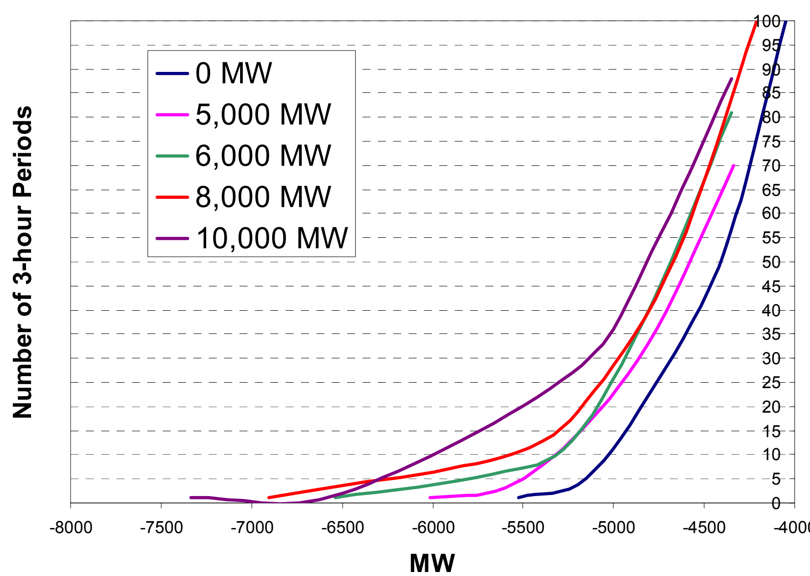


Figure 5.20 Number of Times 3-hour Load Drops Exceed a MW Threshold for Load-Wind Scenarios

The remainder of this chapter examines the load and wind variability in sub-hour time frames to provide a basis for assessing requirements for operating reserve (10-minute), load following (5-minute) and regulation (1-minute).

5.4 Ten-Minute Variability

In the ten-minute time frame, variations in load and wind are a good proxy for contingency events. The current largest contingency exposure on the Ontario bulk power system is 900 MW. To protect against these events, the system carries enough reserve capacity to recover from a 900 MW drop in generation (or increase in load) in 10 minutes. The 10-minute operating reserve requirement is specifically tied to a single contingency, meaning that the reserve is meant to accommodate loss of a single unit, but not a simultaneous drop in generation *and* increase in load. Therefore, in the ten-minute time frame, individual load and wind ten-minute variability are more revealing from an operating reserve point of view than their combined variability. However, since the combined load-wind variability is still the key driver of overall system integrity in any time frame, it will also be characterized here.

5.4.1 Ten-Minute Load Variability

To produce ten-minute load data for analysis, the one-minute resolution data provided by the IESO for 2005 was integrated into 10-minute blocks. The resulting 52,560 load points were then scaled up to the projected 2009 and 2020 levels by applying appropriate scaling factors, and de-trended by taking "first differences" to produce ten-minute load deltas.

To produce a probability distribution of the ten-minute load deltas, the 52,559 data points were sorted into 50 MW bins and plotted on a histogram. Figure 5.21 shows the probability distribution of the ten-minute load deltas for year 2020 load.

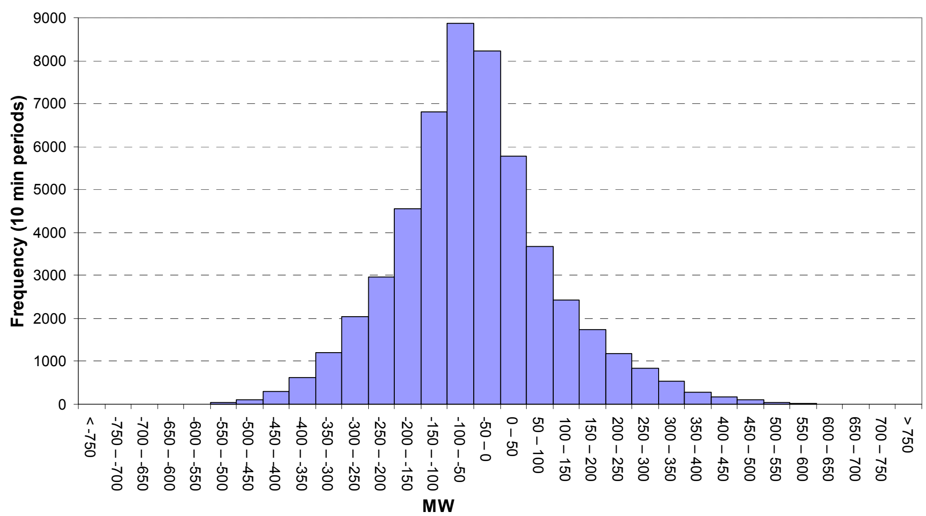


Figure 5.21 Distribution of Ten-Minute Changes for Year 2020 Load

The distribution of the year 2009 hourly load deltas is expected to be similar to the year 2020 load deltas, because they are both derived from the same year 2005 load data. The distribution of ten-minute load deltas shows less spread around the mean than the corresponding distribution of one-hour load deltas. There are 149 ten-minute periods (.28%) where the load drops by at least 500 MW and 27 ten-minute periods (.05%) where the load rises by at least 500 MW. However the majority of ten-minute load changes (97.6%) are less then ± 400 MW. Table 5.11 summarizes the descriptive statistics for the two load series.

Table 5.10 Descriptive Statistics for Year 2009 and 2020 Ten-Minute Load Changes

	2009 Load	2020 Load
Mean	0	0
Std Dev (σ)	133	150
Min Delta	-992	-1124
Max Delta	836	947
Points ≥ 3σ (-/+)	52 / 334	52 / 334
Points ≥ 4σ (-/+)	7 / 26	7 / 26
Points ≥ 5σ (-/+)	1 / 2	1 / 2
Points ≥ 6σ (-/+)	1 / 1	1 / 1

If the year 2020 load deltas are normally distributed, it is expected that 99.7% will be within 3 standard deviations (σ) of the mean (i.e. less than ± 450 MW). In the observed data, there are 334 periods where the load increases more than 450 MW, and 52 periods where the load decreases more than 450 MW, for a total of 386 ten-minute periods (64 hours or .73 %) of "extreme" load changes. By comparison, in the one-hour time frame previously discussed, this number was 12 hours (.14%), which is consistent with the expectation that ten-minute changes are more variable than the one-hour changes. The maximum ten-minute load *drop* is -1124 MW in 2020 and –992 MW in 2009. The maximum ten-minute load rise is 947 MW in 2020 and 836 MW in 2009. The maximum load rise numbers are consistent with Ontario's 900 MW largest single contingency.

5.4.2 Ten-Minute Wind Variability

AWS Truewind provided one year of ten-minute sampled wind data for ten prospective wind groups and a group of existing/signed wind projects. The ten wind groups and the existing/signed projects were combined into aggregate wind penetration scenarios of 1,310 MW, 5,000 MW, 6,000 MW, 8,000 MW and 10,000 MW, by summing and scaling appropriate series as described in Appendix B. The ten-minute wind changes (or deltas) were then produced for each wind scenario by taking the difference between successive data points over the entire year.

A probability distribution of ten-minute wind deltas was constructed for each scenario by sorting the 52,559 data points for each scenario into 100 MW bins and plotting them on a histogram. Figure 5.22 shows the probability distribution of the ten-minute wind deltas for the 10,000 MW scenario.

The probability distribution for the other aggregate wind scenarios, (except for the 1,310 MW scenario), are similar in shape, as expected, and so are not shown here. For the 10,000 MW wind distribution, most of the ten-minute wind changes are within 500 MW of the mean (approximately 99% in fact). However, there are 29 instances (.06%) where the wind output drops by 900 MW or more in ten minutes and 10 instances (.02%) when wind output rises by 900 MW or more in ten minutes.

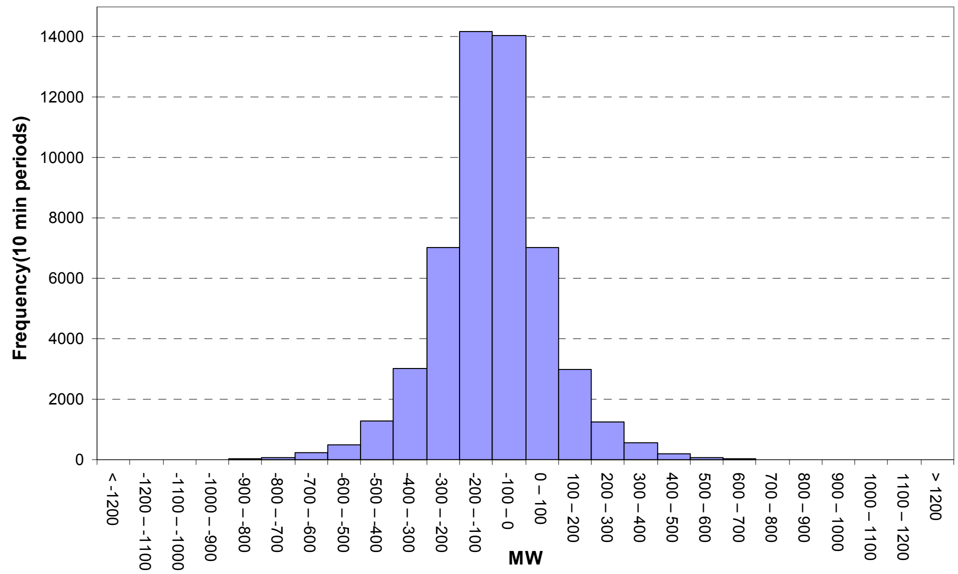


Figure 5.22 Distribution of ten-Minute Changes for 10,000 MW of Wind

Table 5.11 summarizes the descriptive statistics for the five wind penetration scenarios.

Table 5.11 Summary of Ten-Minute Wind Variability for the Five Wind Generation Scenarios

	1310 MW Wind	5000 MW Wind	6000 MW Wind	8000 MW Wind	10000 MW Wind
Mean	0	0	0	0	0
Std Dev (σ)	34	96	113	135	171
Min Delta	-363	-704	-1080	-1130	-1359
Max Delta	478	998	934	1040	1333
Points $\geq 3\sigma$ (-/+)	373 / 415	340 / 363	327 / 371	323 / 316	323 / 310
Points $\geq 4\sigma$ (-/+)	96 / 114	76 / 81	68 / 92	72 / 82	74 / 82
Points $\geq 5\sigma$ (-/+)	33 / 41	17 / 21	22 / 27	19 / 23	18 / 24
Points $\geq 6\sigma$ (-/+)	9 / 17	5 / 4	5 / 10	5 / 10	6 / 8

As in the 1-hour time frame, the variability (as measured by the standard deviation) also increases as the wind output increases, from 34 with 1,310 MW of wind, to 96 with 5,000 MW of wind, and 171 with 10,000 MW of wind. If the wind deltas are normally distributed, it is expected that 99.7% of the ten-minute changes (or 158 deltas) will be within $\pm$ 3-sigma. In the table, for the 10,000 MW wind scenario there are a total of 633 deltas (323 drops and 310 rises) greater than $\pm 3\sigma$ (513 MW), and 14 ten-minute changes (6 drops and 8 rises) greater than $\pm 6\sigma$ (1,026 MW). The single greatest ten-minute drop is 1,359 MW and the single largest ten-minute increase is 1333 MW. In fact, all the wind scenarios except 1,310 MW and 5,000 MW have at least one ten-minute wind drop $\geq$ 900 MW.

In the ten-minute time frame, the extreme drops in wind output are important for determining the incremental for operating reserve requirements.

5.4.3 Ten-Minute Load-Wind Variability

The load-wind variability in the ten-minute time frame is examined for completeness and to provide insight into operating flexibility during this period. As discussed previously, the incremental requirements for operating reserves, as defined by the NPCC[5], can be best derived from the ten-minute wind-alone variability.

Combined load-wind time series were produced for each wind penetration scenario by subtracting the wind series for each penetration level from the appropriate load series. Ten-minute changes (or deltas) were then created by taking the difference between successive data points. The 52,559 load-wind deltas for each scenario were sorted into 50 MW bins and plotted on a histogram. Figure 5.23 shows the probability distribution of ten-minute changes for 2020 load and 10,000 MW of wind combined, along with the ten-minute changes in 2020 load alone on the same plot for comparison. For display purposes, the plot aggregates all ten-minute changes greater than ± 750 MW into single bins at the tails of the distribution. The distributions of ten-minute changes for the other load-wind scenarios are shown in Appendix A.

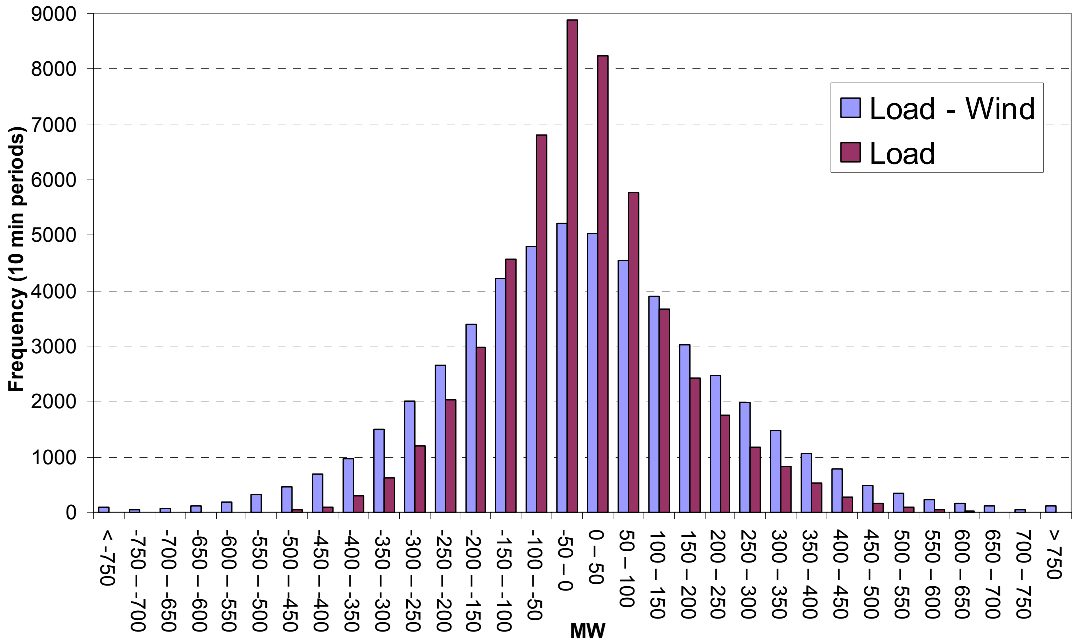


Figure 5.23 Distribution of Ten-Minute Changes for Year 2020 Load and 10,000 MW of Wind

With the addition of 10,000 MW of wind to the year 2020 load, the distribution of load-wind deltas has more spread and is slightly skewed to the left. This is consistent with the observation that often in the late evening and early morning periods when the load is dropping, the wind is picking up, which increases the combined load-wind variability. In Figure 5.23 there are 99 ten-minute periods (.19%) when combined load-wind drops by 750 MW or more and 113 instances (.21%) when combined load-

5 The Northeast Power Coordinating Council's mission is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of criteria, coordination of system planning, design and operations, and assessment of compliance with such criteria.

wind rises by at least 750 MW in ten-minutes. For year 2009 load with 1310 MW of wind (see Appendix A), there are only two instances when combined load-wind changes by at least 750 MW in ten minutes, (one *less* than load alone).

Table 5.12 summarizes the descriptive statistics for ten-minute load-wind deltas.

Table 5.12 Summary of Ten-Minute Variability for the Various Wind Penetration Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	0	0	0	0	0	0	0
Std Dev (σ)	133	137	150	178	188	203	229
Min Delta	-992	-934	-1124	-1114	-1341	-1369	-1460
Max Delta	836	810	947	1009	997	1265	1468
Pts ≥ 3σ (-/+)	52 / 334	65 / 308	52 / 334	89 / 213	123 / 195	133 / 200	158 / 189
Points ≥ 4σ (-/+)	7 / 26	5 / 25	7 / 26	11 / 20	19 / 24	18 / 22	35 / 32
Points ≥ 5σ (-/+)	1 / 2	1 / 3	1 / 2	2 / 4	4 / 2	4 / 3	6 / 3
Points ≥ 6σ (-/+)	1 / 1	1 / 0	1 / 1	2 / 0	1 / 0	1 / 1	1 / 1

As expected, with higher penetration of wind, the variability of combined load-wind increases accordingly. At the 5000 MW wind level, the standard deviation of combined load-wind is 178 MW (a 19% increase over load-alone) and at the 10,000 MW wind level the load-wind standard deviation is increased to 250 MW (a 53% increase over load alone). Along the same line, there is a uniform increase in the number of observed "extreme" ten-minute changes (drops or rises of at least 3σ), from a total of 302 instances with 5000 MW of wind to 346 instances with 10,000 MW of wind (despite a 29% increase in σ from the 5000 MW level to 10,000 MW level).

In the year 2009 scenario, there is a modest 3% increase in the standard deviation of the load-wind ten-minute changes. Interestingly, the maximum ten-minute change is less with 1310 MW of wind than with wind alone. This is due to the fact that the wind happens to be in phase with the load, reducing the net variability during that period.

In Table 5.12, the single greatest ten-minute rise in load-wind with 10,000 MW of wind is 1468 MW. Clearly this ten-minute change exceeds Ontario's 900 MW of 10 minute operating reserve capacity. In fact, only the 2009 scenario lacks a ten-minute load-wind rise ≥ 900 MW. As discussed earlier, the reserve margin is based on a single contingency event and is not meant to account for simultaneous load-wind changes, but under real operating scenarios, this larger magnitude contingency event is a distinct possibility. In fact, with 10,000 MW of wind on the system, there are 32 instances when the combined load-wind change exceeds 916 MW (4σ). These issues will be further explored in the following section.

5.4.4 Operational Impact – Operating Reserves

As mentioned, the Ontario 10-minute operating reserve requirement of 900 MW is based upon the loss of the single largest generation unit. Analysis of the wind data indicates that abrupt loss of all or even large portions of wind generation within Ontario cannot be considered a viable contingency. The persistence of the wind in

Ontario is very high and wind generation diversity limits sudden changes of wind power output (see section 5.6). Notwithstanding, the 10-minute overall variability, maximum 10-minute deltas, and largest 10-minute wind-alone deltas are characterized to provide a basis for determining future operating reserve requirements. Table 5.13 summarizes the ten-minute variability of combined load and wind for all penetration scenarios.

Table 5.13 Summary of Ten-Minute Load-Wind Variability

Case	σ_{Load} **(MW)**	$\sigma_{Load\text{-}Wind}$ **(MW)**	$3\sigma_{Load}$ **(MW)**	$3\sigma_{Load\text{-}Wind}$ **(MW)**	3σ % Increase
2009 Load w/ 1,310 MW	133	137	399	411	3%
2020 Load w/ 5,000 MW	150	178	450	534	19%
2020 Load w/ 6,000 MW	150	188	450	564	26%
2020 Load w/ 8,000 MW	150	203	450	609	35%
2020 Load w/ 10,000 MW	150	229	450	687	53%

The data shows that the overall per unit (or percentage) variability is much greater than the one-hour timeframe, (and on the order of the five-minute timeframe discussed later), ranging from 3% to 53% with increasing wind penetration. Operating reserve requirements, however, are defined more by the extreme events or contingencies on the system. Table 5.14 shows the maximum positive deltas recorded for each of the load-wind scenarios. The increases in maximum positive load-wind deltas for the 1,310 MW, 5,000 MW and 6,000 MW wind scenarios are small relative to load-alone (less than 7%).

Table 5.14 Summary of Ten-Minute Extreme Load-Wind Positive Changes

Case	Max. Positive Load-alone Delta **(MW)**	Max. Positive Load-Wind Delta **(MW)**	% Change from Load-alone to Load-Wind	Max. Negative Wind-alone Delta **(MW)**
2009 Load w/ 1,310 MW	836	810	-3%	-361
2020 Load w/ 5,000 MW	947	1,009	7%	-704
2020 Load w/ 6,000 MW	947	997	5%	-1,080
2020 Load w/ 8,000 MW	947	1,265	34%	-1,130
2020 Load w/ 10,000 MW	947	1,468	55%	-1,359

For the 8,000 MW and 10,000 MW wind scenarios, the increase in the load-wind maximum delta is more significant and worthy of special consideration. As mentioned previously, 10 minute operating reserves are set based upon the sudden loss of the single largest generation unit irrespective of the load variation at the time of the generator loss. The results in Table 5.14 represent the worst-case change in load *and* wind simultaneously. This is certainly a more conservative assessment than the traditional measure of operating reserve. A more conventional approach is to consider the single largest wind-alone drops for each of the scenarios. Extreme drops in wind output over the 10-minute time horizon are analogous to a loss of a generation unit. Figure 5.24 shows the number of times that the wind dropped 900 MW or more over a 10-minute period during a year, for the 5,000 MW to 10,000 MW wind output levels.

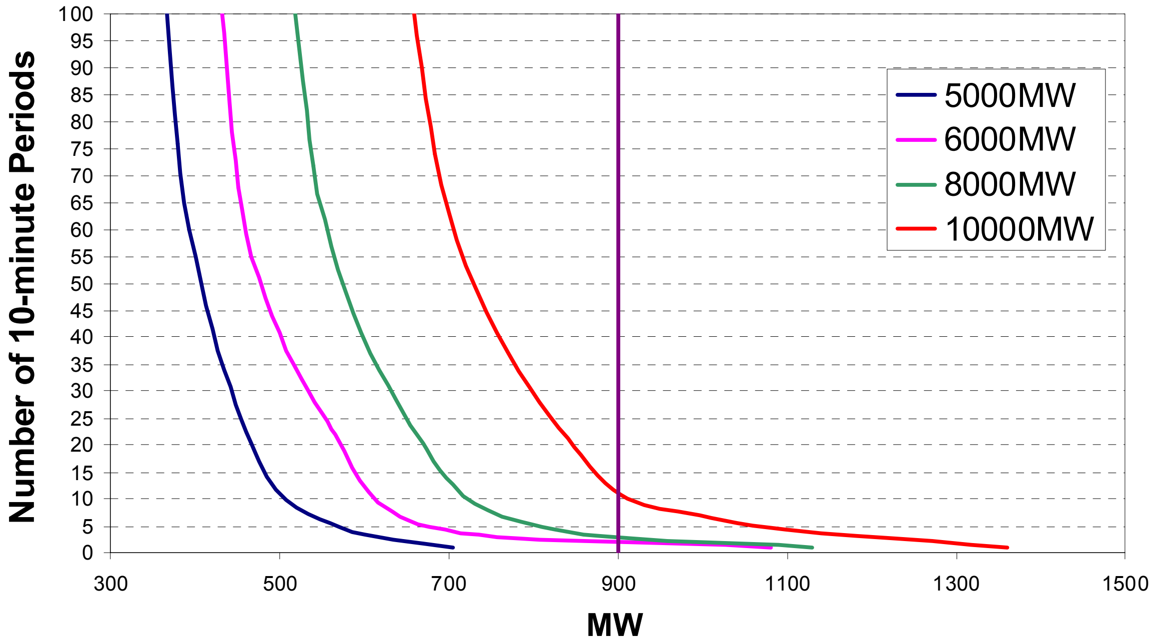


Figure 5.24 Number of Times 10-Minute Wind Drops Exceed a MW Threshold for Various Levels

In all scenarios, with the exception of the 5,000 MW wind case, the wind dropped by over 900 MW at some point during the year. For the 6,000 MW and 8,000 MW cases, the number of periods where the wind dropped more than 900 MW was around four. For the 10,000 MW case, the wind dropped by 900 MW approximately ten times. These results indicate that additional operating reserves will be required to accommodate extreme drops in wind generation.

5.5 Short Term Variability

The analyses presented in the previous sections show that various amounts of wind generation have a slight impact hour-to-hour net variability and a more pronounced impact on ten-minute net variability. The data from these analyses helps frame the discussion on incremental requirements for generation scheduling, ramping and operating reserve. This section will extend the examination of load-wind variability to the short-term (less than ten-minute) periods where load following and regulation operations balance the system under normal conditions.

Within each hour, IESO performs an economic dispatch every five minutes to adjust generation to match the load as it follows its diurnal cycle. Load following is a function provided by generators that adjust their output to match the intra-hour changes in customer load, usually on a five to ten-minute basis. In between load-following adjustments, minute-to-minute changes in customer loads and unintended fluctuations in generation are tracked by regulation units equipped with automatic generation control (AGC). The short-term changes in load and wind are important for determining the additional load-following and regulation services needed for system operation. This section will examine load and wind variability on a five-minute basis for load following and a one-minute basis for regulation.

5.5.1 High Interest Data Periods

In the earlier examination of the ten-minute, one-hour and multi-hour variability, an entire year of data was used to assess the changes in load and wind. As the analysis period becomes smaller, the volume of data increases tremendously. One year of one-minute data is over one half-million data points, which is beyond the capability of most commercial statistical software packages. Furthermore, since seasonal and even diurnal cycles are less important in this time frame, a subset of the data may be sufficient to assess the short-term variability.

For practical reasons, the five-minute and one-minute analyses are focused on a subset of data defined as “high interest periods.” These periods for which high-resolution (one-minute) data were obtained are defined as:

- Periods of high load variability and high load-wind variability (where the load is changing and wind is not helping)
- Periods of high load-wind variability and high wind variability (where wind makes it worse)
- Periods with low load and high load-wind variability (large wind or load variation when generation maneuverability may be low)
- Periods containing the most variable load hours (as measured by load σ)
- Periods during the summer morning load rise, winter afternoon load rise and evening load decline where wind creates operational challenges
- Periods of high wind and low wind variability (good wind resource periods)

Based on these criteria, 24 periods of "high interest" were selected for analysis. The periods, ranging in length from 3 to 24 hours and totaling 180 hours, are listed in Table 5.15 below.

Table 5.15 Listing of the Twenty-Four High Interest Periods for High Resolution Data

	Start Date/Time	End Date/Time	Length (Hrs)	Comments
Large Delta Load Periods				
	6/9/05 3:00 AM	6/9/05 9:00 AM	6	
	6/14/05 3:00 PM	6/14/05 9:00 PM	6	
	7/18/05 3:00 AM	7/18/05 9:00 AM	6	
	5/26/05 4:00 AM	5/26/05 7:00 AM	3	Also contains variable hour
	5/27/05 2:00 PM	5/27/05 5:00 PM	3	Also contains variable hour
	6/29/05 7:00 PM	6/29/05 10:00 PM	3	
	11/29/05 5:00 AM	11/29/05 8:00 AM	3	
Large Delta Wind Periods				
	1/1/05 12:00 AM	1/2/05 12:00 AM	24	Also contains low load period
	1/6/05 3:00 PM	1/6/05 9:00 PM	6	
	3/7/05 9:00 PM	3/8/05 3:00 AM	6	
	11/14/05 3:00 AM	11/14/05 9:00 AM	6	
	7/26/05 11:00 AM	7/26/05 2:00 PM	3	Also contains 2 variable hours
	12/2/05 7:00 PM	12/2/05 10:00 PM	3	
Large Delta Load-Wind Periods				
	4/20/05 3:00 AM	4/20/05 9:00 AM	6	
	7/25/05 3:00 AM	7/25/05 9:00 AM	6	
	7/18/05 8:00 PM	7/18/05 11:00 PM	3	
	12/5/05 4:00 AM	12/5/05 7:00 AM	3	
Low Load Periods with High Delta Load-Wind				
	4/12/05 9:00 PM	4/13/05 3:00 AM	6	
	5/9/05 4:00 PM	5/9/05 10:00 PM	6	
	5/22/05 1:00 AM	5/22/05 7:00 AM	6	
	11/6/05 3:00 AM	11/6/05 3:00 PM	12	Also contains good wind resource period
High Wind Periods with Low Delta Wind				
	3/30/05 4:00 PM	3/30/05 10:00 PM	6	
	11/12/05 9:00 PM	11/13/05 9:00 PM	24	
	11/15/05 9:00 AM	11/16/05 9:00 AM	24	Also contains low load periods
		Total Hours :	**180**	

One-minute wind data were obtained from AWS Truewind for the 24 periods on a group basis. Aggregate wind data for the various penetration scenarios (1,310 MW, 5,000 MW, 6,000 MW, 8,000 MW and 10,000 MW) were created as described in Appendix B, *Load and Wind Data*. The load points corresponding to the one-minute wind data were extracted from the available Ontario load data and scaled up to projected 2009 and 2020 levels. The result produced matched pairs of time-stamped, high-resolution load and wind series for each load and wind scenario (2009 load and 1,310 MW of wind, 2020 load and 5,000, 6,000, 8,000, 10,000 MW of wind) in each of the 24 periods.

The next section describes the five-minute variability for combined load and wind. For brevity, the variability of load-alone and wind-alone on a five-minute basis are not detailed as in previous time frames, but descriptive statistics for load are included in the summary tables for comparison purposes.

5.5.2 Five-Minute Load-Wind Variability

For each of the 24 high-interest periods, five-minute wind data were produced from the one-minute wind data by sampling every five data points. Twenty-four load-wind series for each wind scenario were then created by subtracting the five-minute wind data for each penetration level from the appropriate load series. Within each high-interest period, the five-minute changes in combined load and wind were then produced by taking the difference between successive five-minute data points.

There are two ways to analyze the resulting high-resolution data: individual analysis of the 24 time periods and a joint analysis of the 180 hours. Both approaches are valid, but the results must be interpreted differently. This section describes both approaches and summarizes the results.

5.5.2.1 Individual Analysis of the 24 Periods - Five-Minute

Individual analyses of the 24 periods produces 24 separate load-wind distributions and 24 separate sets of statistics for each period. Table 8.2 to Table 8.6 in Appendix C give the variability statistics for each of the five load-wind scenarios during each of the 24 high-resolution periods. From the data in these tables, Table 5.16 summarizes the results for the three most variable periods (as measured by load-wind σ).

Table 5.16 Summary of 5-Minute Variability During the 3 Most Variable Periods for Five Wind Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
May 27th 2–5 PM							
Std Dev (σ)	349	354	395	419	436	441	457
Min Delta	-1962	-1988	-2221	-2294	-2371	-2391	-2435
Max Delta	445	422	504	545	549	554	577
December 2nd 7–10 PM							
Std Dev (σ)	49	68	56	117	158	169	208
Min Delta	-255	-266	-289	-289	-255	-254	-295
Max Delta	19	146	21	318	511	549	672
November 29th 5–8 AM							
Std Dev (σ)	97	106	110	123	156	173	199
Min Delta	-103	-86	-117	-62	-120	-133	-175
Max Delta	346	366	391	432	609	632	698

The period with the highest variability in Table 5.16 is clearly May 27th 2-5PM (this is an aberration as will be illustrated later). For year 2020 load with 10,000 MW of wind, the standard deviation of five-minute load-wind deltas is 457 MW, (a 62 MW or 16% increase over load-alone), and the maximum 5-minute drop in net load-wind is 2435 MW (a 214 MW or 10% increase over load-alone). This appears to indicate that the introduction of 10,000 MW of wind may push the operating envelope even further than the greatest variation in load-alone would. Figure 5.25 further illustrates this point by plotting the standard deviation (σ) of five-minute deltas for load and load-wind for each of the 24 periods, versus the average *net* load for the period. The scenario is 2020 load with 10,000 MW of wind.

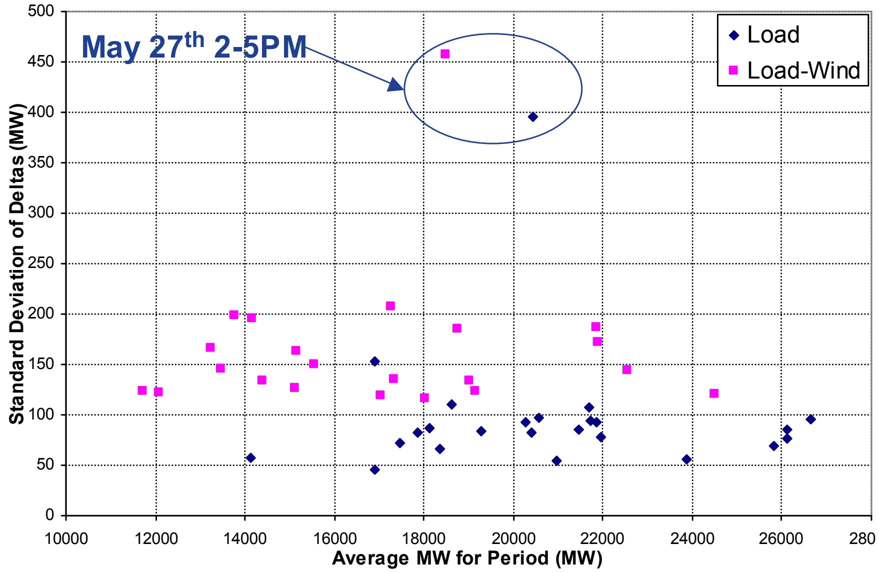


Figure 5.25 Five-Minute σ for Each Period vs. Average Net Load - 2020 Load w/ 10,000 MW Wind

For all periods, there is a general tendency for the standard deviation of the net load deltas to shift up and to the left with the addition of wind. However, the variability of net load during May 27th 2–5 PM, is far above that of the next two most variable periods listed in Table 5.16. The fact that every other period has significantly less variability than May 27th 2–5 PM, suggests that there is an aberration during this period (confirmed to be tripping of two 230 kV circuits which dropped 2000 MW of load). For illustration, Figure 5.26 shows the time series plot for May 27th 2-5 PM.

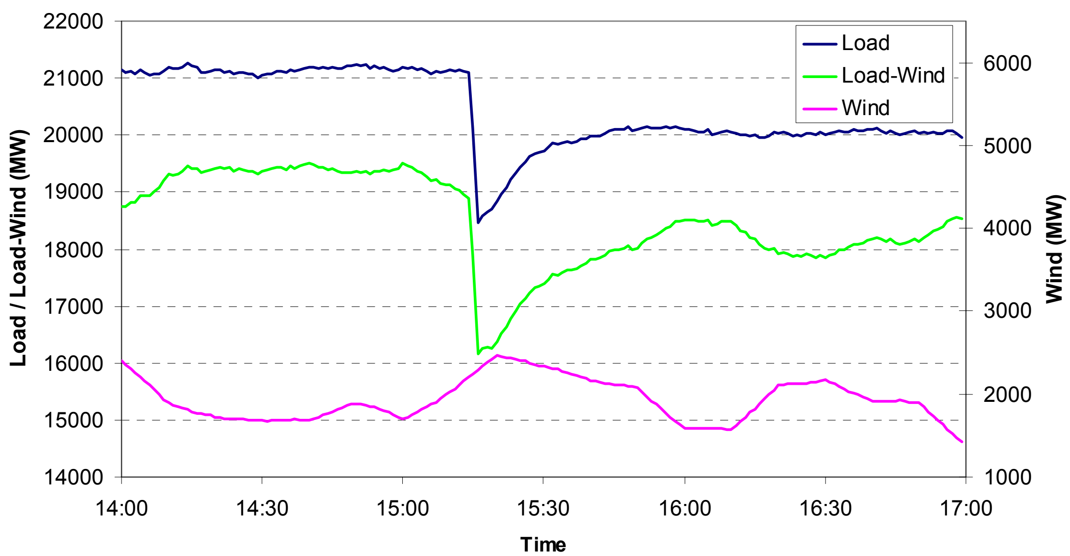


Figure 5.26 Time Series Plots for 2020 Load and 10,000 MW of Wind During May 27th, 2–5 PM

At the precise moment when the load drops precipitously around 3:15 PM, wind happens to be ramping up, which accounts for the significant five-minute change in combined load-wind during the period. By contrast, the largest five-minute change during the next most variable period, December 2nd 7-10 PM, is mostly caused by a large drop in wind output, (about 7% of rated). For the third most variable period, November 29th 5-8 AM, the largest five-minute change is caused by a combination of a load rise and a simultaneous drop in wind output. These two time periods are more illustrative of the "extreme" operating case than the May 27th 2-5 PM period.

5.5.2.2 Joint Analysis of the 180 Hours - Five-Minute

An overall analysis of the 180 hours of high-resolution data simply means that the 24 separate series of load-wind deltas from each period are concatenated into one (joint) series and analyzed together. The analysis approach is identical to the one-hour and ten-minute analysis, except that instead of one full year of data, 180 hours during the most variable and extreme periods are used.

The key difference between the result from this approach and results from the previous approach ("Individual Analysis of the 24 Periods") is the standard deviation (σ) of the load-wind deltas. In the previous approach, an estimate of σ was obtained for *each* of the 24 periods separately, and was only appropriate for characterizing variability within the specific period. In this case, one estimate of σ is obtained for all 180 hours jointly and is appropriate for characterizing variability over the 180 hours. By proxy, this estimate could be extended to characterize the five-minute variability over the entire year. Since the 180 hours represent the most extreme and variable 2% of the year, they are likely to give a conservative estimate of additional operational requirements for load following. This will be further discussed in the following *Operational Impacts* section.

Figure 5.27 shows the probability distribution of five-minute changes for the 180 hours of high-resolution data from the 2020 load with 10,000 MW of wind scenario.

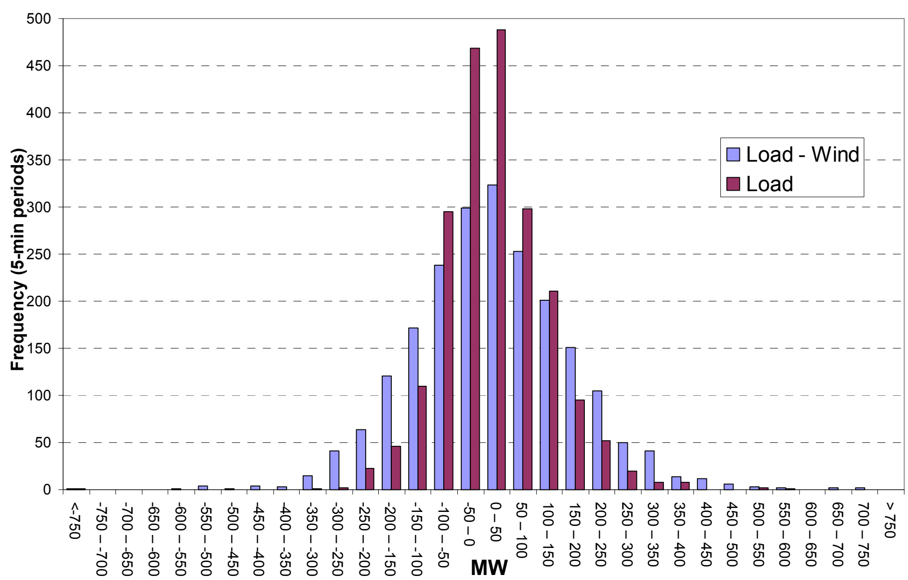


Figure 5.27 Distribution of 5-Min Changes for 2020 Load-10,000 MW Wind (180 Hours High Res Data)

The plot shows that when 10,000 MW of wind is added to the 2020 load, the distribution of net load-wind changes becomes broader, with approximately 97.4% of the deltas within ±350 MW, compared with 99.4% for load alone. There are 14 five-minute periods (.65%) where combined load-wind drops by at least 350 MW (compared with 1 period for load-alone), and 41 instances (1.9%) when combined load-wind rises by at least 350 MW in five minutes (compared with 11 for load-alone).

Table 5.17 summarizes the five-minute variability for load and combined load-wind for the various wind penetration scenarios, using the full 180 hours of data.

Table 5.17 Summary of 5-Min Variability for the Five Wind Scenarios (180 Hours High-Resolution Data)

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	16	16	19	20	19	19	19
Std Dev (σ)	97	100	110	128	136	145	161
Min Delta	-1961	-1987	-2221	-2294	-2371	-2391	-2435
Max Delta	508	496	575	549	609	634	732
Points ≥ 3σ (-/+)	2 / 11	1 / 12	2 / 11	1 / 11	3 / 11	3 / 9	7 / 9
Points ≥ 4σ (-/+)	1 / 3	1 / 3	1 / 3	1 / 2	1 / 1	1 / 3	1 / 4
Points ≥ 5σ (-/+)	1 / 1	1 / 0	1 / 1	1 / 0	1 / 0	1 / 0	1 / 0
Points ≥ 6σ (-/+)	1 / 0	1 / 0	1 / 0	1 / 0	1 / 0	1 / 0	1 / 0

As the amount of wind on the system increases, the variability of combined load-wind (as measured by σ) also increases, as expected. With 5,000 MW of wind, the standard deviation of combined load-wind deltas is 128 MW (an 18 MW or 16% increase over load-alone), and with 10,000 MW of wind, the σ of the deltas increases to 161 MW (a 51 MW or 46% increase over load-alone). In the year 2009 scenario, the addition of 1,310 MW of wind increases σ of the load-wind deltas by about 3 MW or 3% over load-alone.

In all scenarios, the addition of various amounts of wind also serves to increase the largest 5-minute change in net load-wind. In year 2020, with load-alone, the largest change is a drop of 2,221 MW. With 10,000 MW of wind added, the largest 5-minute change is a drop of 2,435 MW (a 214 MW or 10% increase over load-alone). In year 2009, the addition of 1,310 MW of wind increases the largest 5-minute change by 26 MW or 1.3%.

The implications of these observations for operational requirements are further discussed in the next section.

Moving Window Analysis - The joint analysis of the 180 hours of data can be extended to a moving window analysis to capture all possible five-minute deltas. This approach produces all possible five-minute load-wind deltas by shifting the starting point for the first sample by 1, 2, 3 or 4 one-minute periods. The five-minute moving window analysis is further described and summarized in Appendix C.

5.5.2.3 Operational Impacts – Load Following

In Ontario, generators are re-dispatched every 5 minutes to accommodate overall system changes and to "follow" changes in load. Load changes in the 5-minute are more variable than the 10-minute time frame, but more predictable than the one-minute changes, and generally follow a similar day-to-day pattern.

The data used for this analysis is based upon 180 hours of the most extreme and variable periods during the year. Since this subset of time series data is not "typical" or necessarily representative of normal operation, the 5-minute analysis results for load following are likely to be *conservative*. In this study, the incremental load following requirement is defined as the increase in three standard deviations (3σ) of the 5-minute deltas between load-wind (load minus wind) and the load alone. For a normal distribution, the area under the curve within 3σ of the mean covers 99.73% of all outcomes. This definition of incremental load following is consistent with previous study work and generally consistent with the current operating practice. Table 5.18 summarizes the five-minute variability of load and load-wind to characterize the incremental load following requirements.

Table 5.18 Summary of Load Following Operating Requirements in the Five-Minute Timeframe

Case	σ_{Load} (MW)	$\sigma_{Load\text{-}Wind}$ (MW)	$3\sigma_{Load}$ (MW)	$3\sigma_{Load\text{-}Wind}$ (MW)	3σ % Increase	$3\sigma_{Load\text{-}Wind} - 3\sigma_{Load(5min)}$ (MW)
2009 Load w/ 1,310 MW	96.8	100.1	290.4	300.3	3.4%	10
2020 Load w/ 5,000 MW	109.7	128.2	329.1	384.6	17%	56
2020 Load w/ 6,000 MW	109.7	136.1	329.1	408.3	24%	80
2020 Load w/ 8,000 MW	109.7	145.2	329.1	435.6	32%	107
2020 Load w/ 10,000 MW	109.7	161.3	329.1	483.9	47%	155

The incremental variability in the five-minute timeframe is slightly less than the 10-minute time frame, but more significant than with the one-minute timeframe, which is discussed later. The year 2009 Load with 1,310 MW of planned or existing wind generation needs an additional 3.4% of load following capability. This additional load following duty should be accommodated with the existing generators. The year 2020 Load with 10,000 MW of wind generation scenario needs an additional 47% of load following maneuverability. In other words, in the year 2020 the non-wind supply mix must be able to provide an additional 47% of load following to maintain performance. It is important that any future supply mix strategy recognize that wind generators will likely displace more flexible generation resources and the remaining balance-of-portfolio resources must be able to accommodate this additional variability.

5.5.3 One-Minute Load-Wind Variability

In the same manner that the five-minute data is analyzed, the one minute data can also be analyzed to provide insight into additional requirements for regulation. This section presents the results of an individual analysis of the 24 extreme and variable time periods, and a joint analysis of the 180 hours.

5.5.3.1 Individual Analysis of the 24 Periods - One-Minute

For each of the 24 separate periods, the one-minute variability of combined load and wind is analyzed for each of the five wind scenarios. Table 8.2 to Table 8.6 in Appendix C lists the full results of the analyses. Table 5.19 below summarizes the results for the three most variable periods *in the one-minute timeframe* (as measured by load-wind σ). The statistics for load-alone are also included for comparison.

Table 5.19 Summary of 1-Minute Variability During the 3 Most Variable Periods for Five Wind Scenarios

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
May 27th 2–5 PM							
Std Dev (σ)	133	134	151	153	156	157	159
Min Delta	-1469	-1473	-1663	-1675	-1698	-1702	-1713
Max Delta	134	126	152	134	134	136	141
July 26th 11 AM–2 PM							
Std Dev (σ)	93	93	105	107	107	109	111
Min Delta	-695	-708	-787	-814	-844	-838	-849
Max Delta	686	675	776	748	716	716	702
May 26th 4–7 AM							
Std Dev (σ)	63	63	72	72	72	73	73
Min Delta	-87	-83	-99	-98	-98	-100	-101
Max Delta	504	501	571	567	570	571	571

As in the five-minute time frame, the period with the highest variability in the one-minute time frame is also May 27th 2-5 PM, which was shown to be an aberration. During this 3-hour period, the standard deviation of one-minute load-wind deltas only increases marginally from 151 MW to 159 MW (a 5% increase) with the addition of 10,000 MW of wind. At the same time, the maximum one-minute drop goes from 1663 MW with no wind, to 1713 MW with 10,000 MW of wind (a modest 3% increase).

The next two most variable periods happen to be different from those in the five-minute time frame. During the period July 26th 11 AM–2 PM, there is a 6 MW increase in σ and a 62 MW increase in the maximum delta with the addition of 10,000 MW of wind. This time period also happens to be an aberration, as explained later. During the third period, May 26th 4–7 AM, there is a 1 MW increase in σ and a 4 MW increase in the maximum delta with 10,000 MW of wind.

These three periods *may* represent the outer edge of the operating spectrum, where the load variation is driving the contingency. Figure 5.28 further illustrates this point by plotting the standard deviation (σ) of one-minute deltas for load and load-wind for each of the 24 periods, versus the average *net* load for the period. The scenario is year 2020 load with 10,000 MW of wind.

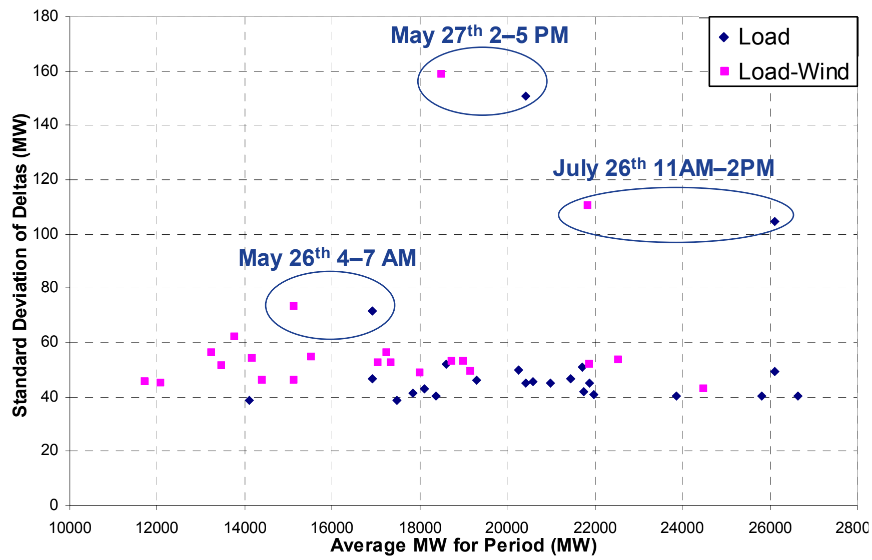


Figure 5.28 One-Minute σ for each Period vs. Average Net Load - 2020 Load w/ 10,000 MW Wind

As expected, there is a general tendency for the standard deviation of the net load deltas to shift up and left with the addition of wind. Net variability during the three periods listed in Table 5.19 is clearly higher than any other period, which might suggest that they are *not* representative of the "typical" extreme operating condition.

For May 27th 2-5PM, Figure 5.26, (shown earlier) illustrated that the variability is due to a large drop in load (when two 230 kV circuits tripped), and a simultaneous increase in wind output. Figure 5.29 shows the time series plots for load, wind, and combined load-wind during the next most variable period, July 26th 11AM–2PM, for 2020 load with 10,000 MW of wind.

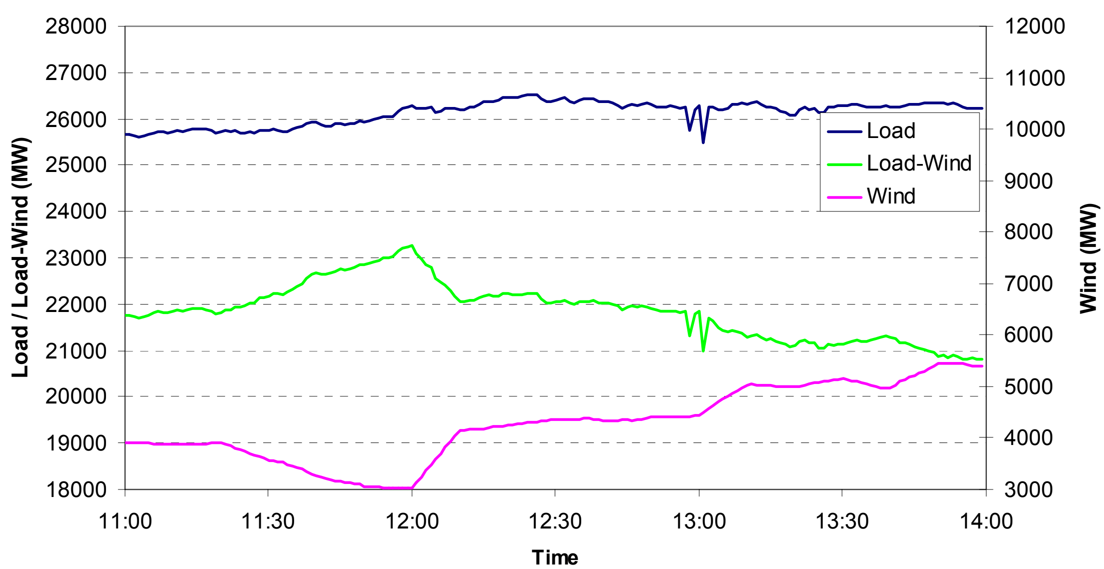


Figure 5.29 Time Series Plots for 2020 Load and 10,000 MW Wind During July 26th 11AM–2PM

From the plots, it is clear that the large one-minute drop of 849 MW in net load-wind, followed by a rise of 702 MW are strictly due to apparent rapid load excursions occurring around 1:00 PM. Data from the IESO confirms that there was faulty telemetry from the Nanticoke plant, which drove these oscillations. Disregarding these anomalous (possibly erroneous) changes, the next largest one-minute change in net load-wind is 213 MW occurring around 12:00 PM.

The third most variable time period, May 26th 4–7 AM, may be closer to "typical" extreme one-minute variability, at the outer edge of the operating envelope. During this summer morning load rise period, the load is rising rapidly while the wind is relatively flat or decreasing slightly. In this case, the operational challenge, from a regulation point-of-view, would be mostly due to the large one-minute load changes, where the wind output is not helping. These issues are further examined in the *Operational Impacts* section.

5.5.3.2 Joint Analysis of the 180 Hours - One-Minute

The 180 hours of high resolution data are analyzed together to provide an overall picture of load-wind variability during the top 2% most variable hours of the year. The results of the analysis can be extended to provide a *conservative* estimate of additional requirements for regulation.

Figure 5.30 gives the probability distribution of one-minute changes for the 180 hours of high-resolution data. The deltas represent the year 2020 load with 10,000 MW of wind scenario. For display purposes, the plot aggregates all one-minute changes greater than ±200 MW into single bins at the tails of the distribution.

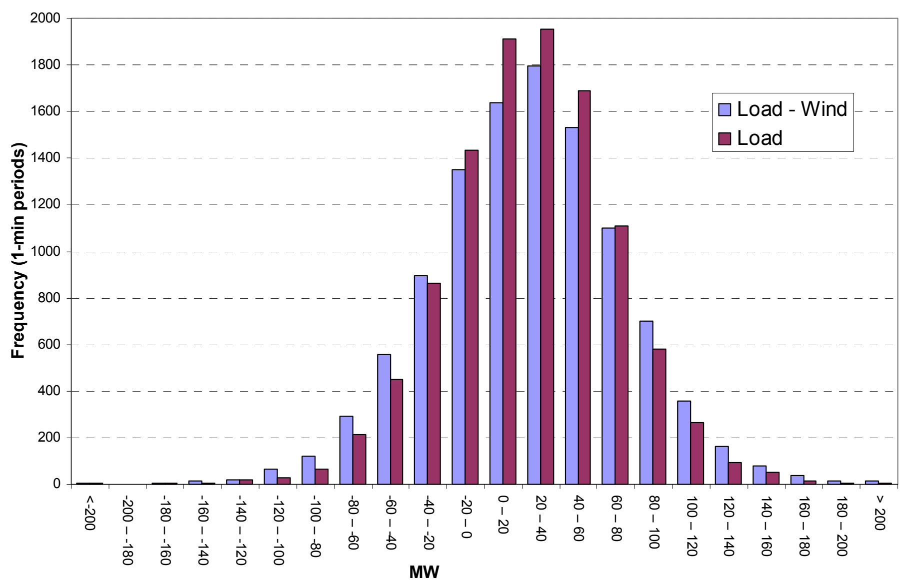


Figure 5.30 Distribution of 1-Min Changes for 2020 Load-10,000 MW Wind (180 Hours High Res Data)

When 10,000 MW of wind is added to the year 2020 load, it tends to somewhat broaden and flatten the distribution of the combined load-wind deltas. In the distribution plot, approximately 99.2% of the deltas are within ±160 MW, which is slightly less than the 99.6% for load alone. In addition, there are 12 instances (.1%)

when combined load-wind drops by at least 160 MW in one minute (compared with 9 for load-alone), and 65 instances (.6%) when the rate of load-wind rise is ≥ 160 MW/min, compared with 25 for load-alone.

Table 5.20 summarizes the one-minute variability for load and combined load-wind for the various wind penetration scenarios, based on the full 180 hours of data.

Table 5.20 Summary of 1-Min Variability for the Five Wind Scenarios (180 Hours High-Resolution Data)

	2009 Load	w/ 1310 MW Wind	2020 Load	w/ 5000 MW Wind	w/ 6000 MW Wind	w/ 8000 MW Wind	w/ 10000 MW Wind
Mean	3	3	4	4	4	4	4
Std Dev (σ)	45	45	51	53	53	54	56
Min Delta	-1468	-1472	-1663	-1675	-1698	-1702	-1713
Max Delta	685	675	776	748	716	716	702
Points ≥ 3σ (-/+)	25 / 19	23 / 19	25 / 19	25 / 21	24 / 21	22 / 21	21 / 27
Points ≥ 4σ (-/+)	6 / 11	7 / 11	6 / 11	7 / 11	5 / 11	5 / 11	4 / 11
Points ≥ 5σ (-/+)	4 / 8	4 / 8	4 / 8	4 / 8	4 / 8	4 / 7	4 / 7
Points ≥ 6σ (-/+)	4 / 7	4 / 7	4 / 7	4 / 7	4 / 7	4 / 7	4 / 6

Similar to the five-minute time frame, these results confirm that as the amount of wind on the system increases, the variability of combined load-wind (as measured by σ) increases, but only marginally so. In this time frame, overall load-wind variability is dominated much more by the load than the wind. This is evidenced by an approximate 10% increase in σ with 10,000 MW of wind. In the year 2009 scenario, the addition of 1310 MW of wind has little observable impact on the overall variability.

However, in all scenarios, the addition of various amounts of wind tends to increase the largest one-minute change in net load-wind. In year 2020, with 10,000 MW of wind, the largest five-minute change in combined load-wind is –1713 MW, a 50 MW increase over the load-alone case. In year 2009, the addition of 1310 MW of wind increases the largest 5-minute change by 4 MW.

The implications of these observations for operational requirements with regard to regulation are further discussed below.

5.5.3.3 Operational Impacts – Regulation

Regulation is defined as the use of online generating units via Automatic Generator Control (AGC) to adjust for short time frame (seconds to minutes) changes in system conditions.[6] System changes may be characterized by unpredictable small variations in system load or unexpected changes in online generation resources. By continuously adjusting, regulating generation units act to maintain system frequency and adjust for mismatches between scheduled control area interchanges and actual interchanges. Wind generators add to the overall system variability and, inherently, to the regulation requirements. The degree to which the regulation requirement is

[6] Hirst, E. and Kirby, B. "Separating and Measuring the Regulation and Load Following Ancillary Services" November, 1998 (available at www.EHirst.com)

impacted is based upon the increase of the standard deviation (σ) of the 1-minute deltas (change from one minute to the next) from the load-alone cases to the load with wind cases.

As mentioned previously, the one-minute data used in this analysis is based on 180 hours of the most extreme and variable periods during the year. Since this subset of time series data is not necessarily representative of typical operations, the results of the one-minute analysis for regulation are likely to be *conservative*. In this study, the incremental regulation requirement is defined as the increase in three standard deviations (3σ) of the one-minute deltas between load-wind (load minus wind) and the load alone. For a normal distribution, 99.73% of all data are within 3σ of the mean. This definition of regulation is consistent with previous study work and generally consistent with the current operating practice in Ontario. In 2005, the contracted AGC was +/- 150MW, and the 3σ of one-minute deltas for 2005 load-alone is 130 MW. Table 5.21 summarizes the one-minute variability of load and load-wind to characterize the incremental regulation requirements.

Table 5.21 Summary of Regulation Operating Requirements in the One-Minute Timeframe

Case	σ_{Load} (MW)	$\sigma_{Load-Wind}$ (MW)	$3\sigma_{Load}$ (MW)	$3\sigma_{Load-Wind}$ (MW)	3σ % Increase	$3\sigma_{Load-Wind}$ - $3\sigma_{Load(5min)}$ (MW)
2009 Load w/ 1,310 MW	44.7	45.1	134.1	135.3	0.9%	1
2020 Load w/ 5,000 MW	50.7	52.6	152.1	157.8	4%	6
2020 Load w/ 6,000 MW	50.7	53.4	152.1	160.2	5%	9
2020 Load w/ 8,000 MW	50.7	54.5	152.1	163.5	6%	12
2020 Load w/ 10,000 MW	50.7	56.5	152.1	169.5	11%	18

The results of the regulation analysis show that the incremental regulation required to maintain the current performance is small. Although it is very important for all stakeholders to evaluate these results as part of their planning process, we believe that the impact on regulation of 10,000MW of wind generation by the year 2020 is modest and can be accommodated with little or no changes to existing operating practices.

5.6 Sudden Weather Change Analysis

Wind generation is a valuable commodity that can enable the reliable and economic operation of power systems. However, because of the intrinsic variability of wind, and the unpredictability (to some extent) of weather systems in general, there is a real possibility that wind output will not be available when it is needed.

For the purposes of this study, there are three scenarios of interest that would disrupt or curtail wind generation on the Ontario bulk power system:

- Sudden reductions in wind speed (across 10 minutes or less)
- Sudden increases in wind speed which cause wind generators to be stopped quickly for physical protection
- Extremes of weather incidents such as extreme operating temperatures or icing events associated with the Great Lakes which may force facility outages

This section will discuss and quantify (where possible) the likelihood of such events occurring by examining the historical wind data and weather patterns.

5.6.1 Wind Persistence

Wind persistence, for the purposes of this study, is defined as the tendency for wind to maintain its strength level over short time periods (less than ten minutes). In other words, it characterizes the reluctance of wind to change amplitude suddenly. High wind persistence can be confirmed or observed by looking at the autocorrelation function of the wind time series, and the state transition probabilities of wind output.

5.6.1.1 Wind Autocorrelation

An autocorrelation (self-correlation) function computes and plots the autocorrelation coefficients of a time series; which is the correlation between observations separated by n time units. With regard to a wind series, autocorrelation characterizes the nature of the relationship between wind at time t and wind at some later time $t+n$ (where n is the number of time periods elapsed since time t). The expectation is that as n grows larger, the strength of the relationship between wind at time t and $t+n$ will weaken. The rate at which the relationship weakens is directly tied to the wind persistence. The slower the rate of decrease, the higher the degree of wind persistence.

In any relationship between two variables, the correlation coefficient of regression, r, can be used to indicate the strength and nature of the relationship. If r is high (close to 1), then the two variables are highly correlated. If r is low (close to 0), then they are not. The sign of r indicates positive or negative correlation.

Figure 5.31 shows the autocorrelation plot for one year of 10-minute sampled wind data. Each bar on the plot represents one 10-minute time lag, and the height of the bar gives the strength of the correlation between an observation at time t and an observation at time $t+n$. For example, the plot shows that the correlation coefficient between wind separated by ten-minutes is $r = .99$. This means that there is a very strong relationship between wind separated by ten-minutes in time. The autocorrelation function slowly decreases, to where, at n = 50, *r* = .7, and at n = 250, *r* is close to zero.

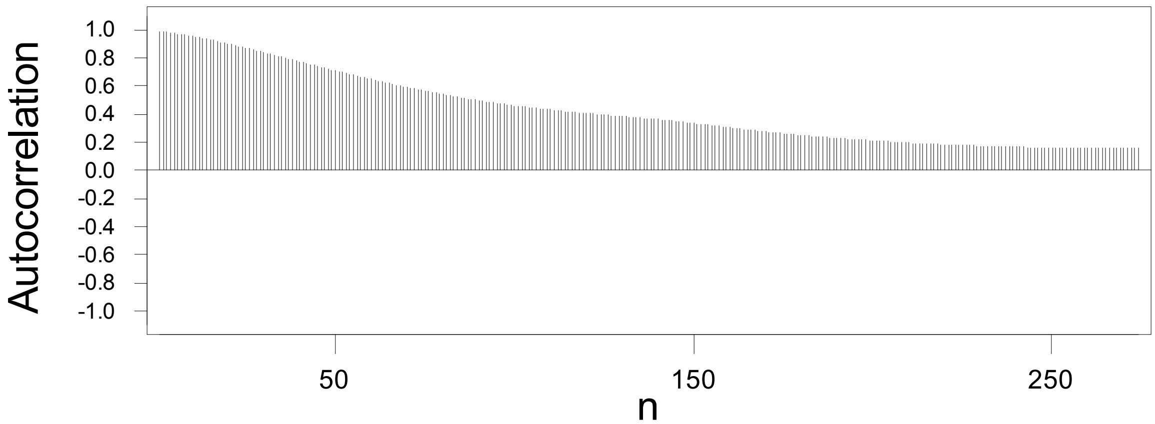


Figure 5.31Autocorrelation Function for ten-minute Wind Data

This data must be interpreted with care. The autocorrelation coefficient, *r*, does *not* equate to the probability that wind will remain at the same level. It simply indicates that the current level of wind output is a key factor in determining the future output level, i.e. there are not *likely* to be random sudden variations from one output level to another over a short time period. The next subsection expands on this observation by quantifying the probability of wind transition between discrete output levels.

5.6.1.2 Wind Transition Probabilities

The state transition probability of wind is the probability that wind output will change from one state to another over a given time period. To quantitatively address the issue of wind persistence, state transition probabilities are empirically derived from the ten-minute and one-minute wind data provided by AWS Truewind

For each wind data point, a delta (or difference between the point and the next point) was computed. The wind output was then expressed as a percentage of the rated capacity, and the %output and associated deltas were sorted into ten bins. Within each of these ten bins, the probability that the wind output will transition to another bin in the next time period was computed based on the deltas. The results of the analysis were collected into a state transition matrix.

Figure 5.32 shows the state transition matrix for 10-minute wind, which is based on one year of sampled wind data. The first column represents the current state or the present wind output as a percentage of rated capacity. The first row gives the next state or the wind output level in ten-minutes, as a percentage of rated capacity. For example, when wind output is at 41-50% of rated, there is a probability of .8250 that it will remain in that range, a .1018 probability that it will drop to 31-40% of rated, and a .0732 probability that wind will rise to 51-60% of rated, all in the next ten minutes.

Next State(Output, % rated capacity)

Current State (Output)	0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
0-10%	0.8256	0.1744	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-20%	0.0448	0.8990	0.0562	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21-30%	0.0000	0.0758	0.8619	0.0621	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000
31-40%	0.0000	0.0000	0.0929	0.8367	0.0704	0.0000	0.0000	0.0000	0.0000	0.0000
41-50%	0.0000	0.0000	0.0000	0.1018	0.8250	0.0732	0.0000	0.0000	0.0000	0.0000
51-60%	0.0000	0.0000	0.0000	0.0000	0.1197	0.8046	0.0757	0.0000	0.0000	0.0000
61-70%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0930	0.8249	0.0822	0.0000	0.0000
71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1424	0.8230	0.0345	0.0000
81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1154	0.8438	0.0409
91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1156	0.8844

Figure 5.32 State Transition Matrix for Ten-Minute Wind

The diagonal probabilities (shaded yellow) characterize the wind persistence. They show that *on average* there is an 84% chance that wind output will persist, i.e. that it will change by no more than 10% of rated capacity in ten minutes. The immediate off-diagonal probabilities (shaded blue and green) represent the probability for significant change. They indicate that there is an *average* probability of .16 that wind output will transition to an adjacent bin-level in ten minutes. Beyond the immediate off-diagonal probabilities, everything else is virtually zero. This means that from the observed data, there is virtually no chance that wind will change by more than 20% of rated in ten minutes.

Figure 5.33 shows the state transition matrix for one-minute wind. Unlike the ten-minute matrix, this is based on only 180 hours of one-minute wind data sampled during the most extreme and variable periods of the year.

Next State (Output, % rated capacity)

Current State (Output)	0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
0-10%	0.9007	0.0993	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-20%	0.0029	0.9873	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21-30%	0.0000	0.0069	0.9841	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
31-40%	0.0000	0.0000	0.0136	0.9779	0.0085	0.0000	0.0000	0.0000	0.0000	0.0000
41-50%	0.0000	0.0000	0.0000	0.0076	0.9764	0.0160	0.0000	0.0000	0.0000	0.0000
51-60%	0.0000	0.0000	0.0000	0.0000	0.0183	0.9756	0.0061	0.0000	0.0000	0.0000
61-70%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081	0.9776	0.0142	0.0000	0.0000
71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0082	0.9863	0.0055	0.0000
81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0062	0.9776	0.0162
91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0147	0.9853

Figure 5.33 State Transition Matrix for One-Minute Wind

The structure of this matrix is the same as the ten-minute matrix shown previously, but the transition probabilities out of the current state are much lower. This is expected because wind is more likely to be the same (higher correlation) in a smaller time frame and more likely to change over a longer period. In this case, when wind output is at 41-50% of rated, there is a probability of .9764 that it will remain in that range, a .0076 probability that it will drop to 31-40% of rated, and a .0160 probability that wind will rise to 51-60% of rated, all in the next minute.

The diagonal probabilities (shaded yellow) show that *on average* there is a 97% chance that wind output will not change by more than 10% of rated capacity in one minute. The off-diagonal probabilities (shaded blue and green) indicate that there is an *average* probability of .03 that wind output will transition to an adjacent bin-level in ten minutes. Beyond that, the observed data shows that there is virtually no chance wind will change by more than 20% of rated over a minute.

The preceding discussion makes a good case for the assertion that "sudden" changes in wind output are not *likely* to occur over short time periods. However, this is only part of the story. When sudden changes *do* occur (regardless of how infrequently), the spatial diversity in wind site/group locations will tend to reduce the impact of individual changes on the aggregate output. The next subsection examines the correlation between wind at different locations in Ontario and impact of diversity.

5.6.2 Wind Group Diversity

In a province the size of Ontario, wind is never the same everywhere and in fact, varies considerable from time period to time period in different locations. This is a well-known fact and for this very reason individual turbines within a wind farm and individual wind farms within a territory are sited to take advantage of diversity. An examination of the wind groups that make up the various wind scenarios in Ontario reveals that there is significant spatial diversity, and consequently wind diversity from group to group. This subsection will examine wind diversity from two aspects: group correlation and group coincidence. Conclusions from the group analysis can be extended to wind sites because individual wind sites are likely to exhibit even more diversity than the groups into which they are aggregated.

5.6.2.1 Group Wind Correlation

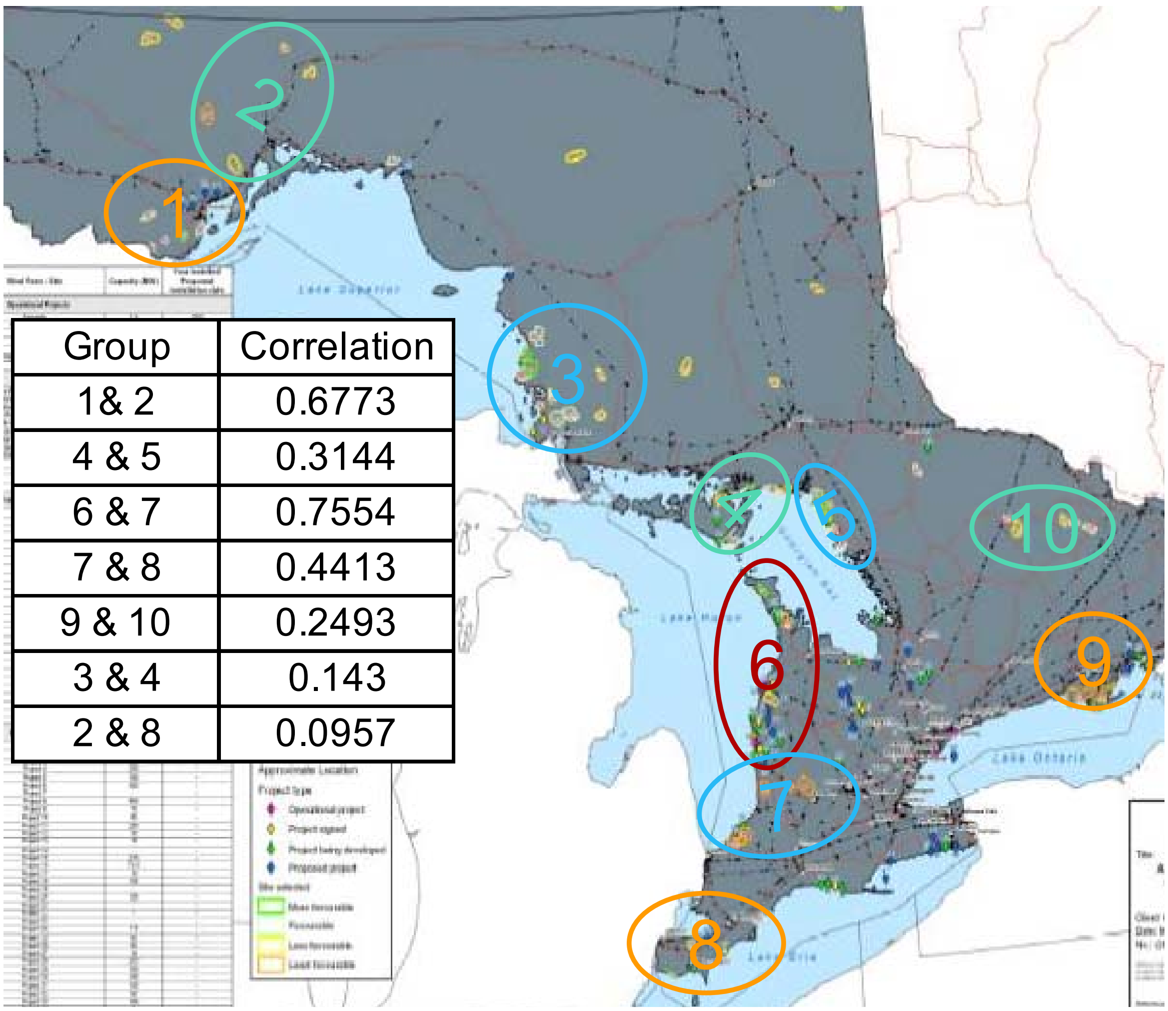
As explained in Chapter 3, *Wind Production Profiles*, the 68 Helimax wind sites were divided into ten wind groups based on geography, plus a group of existing/signed projects. A summary of the grouping for the 56 prospective sites is given in Table 5.22.

Table 5.22 Summary of Grouping for Prospective Wind Sites

Group	Region	# Sites	Group	Region	# Sites
1	Western Ontario	7	6	Bruce Peninsula to Goderich	4
2	North shore of Lake Superior	5	7	Goderich to London	5
3	East shore of Lake Superior	10	8	Northern shore of Lake Erie	3
4	North of Georgian Bay	9	9	North shore of Lake Ontario	2
5	East shore of Georgian Bay	6	10	Lake Simcoe to Lake Nipissing	5

Ten-minute data for an entire year was available for each of the ten wind groups. Based on this data, the correlation coefficients between various group pairs (mostly adjacent wind groups) were computed. As explained previously, the correlation coefficient, *r*, can be used to characterize the strength of the relationship between two variables. If *r* is high (close to 1), then the two variables are highly correlated. If *r* is low (close to 0), then they are not. The sign of *r* indicates positive or negative correlation.

Figure 5.34 shows the location of the ten wind groups and the correlation coefficient between selected pairs of wind groups.



Group	Correlation
1& 2	0.6773
4 & 5	0.3144
6 & 7	0.7554
7 & 8	0.4413
9 & 10	0.2493
3 & 4	0.143
2 & 8	0.0957

Figure 5.34 Group Locations and Correlation Coefficient of Various Parings for 10-Minute Wind Data

The data shows that the strongest correlation (.6773) exists between groups 1 and 2, both in Western Ontario on the northern shore of Lake Superior. Despite the close proximity and common-mode lake effects, the correlation coefficient is not very high. The weakest correlation in the list is between groups 3 and 4 and groups 2 and 8 which happen to be the furthest apart (approximately 1000 km).

The story here is that over a ten-minute period, different wind groups, even if they are in close proximity, are not likely to exhibit synchronous changes in output. The longer the geographic distance between groups, the less correlated they are likely to be, and the ten-minute changes are likely to be more independent of each other.

A similar examination of the 180 hours of one-minute data (from the 24 most extreme and variable periods) supports the same general conclusion for shorter periods -- although the correlation coefficients are noticeable higher over one minute than over ten minutes.

The lack of inter-group correlation is important because it is a key determinant of group coincident behavior. Low group coincidence means than extreme events that occur within a particular group will be curtailed in the aggregate wind output due to group diversity.

5.6.2.2 Group Wind Coincidence

Because wind output in the various groups are not particularly closely correlated, it stands to reason that large changes in wind output are not like to be coincident across groups, i.e. group wind will not experience simultaneous rise and fall in output. The degree to which group wind coincidence (or lack thereof) reduces the impact of individual group events on the aggregate wind can be quantified by coincidence factors. The concept is similar to coincidence factors used in load diversity studies. Table 5.23 illustrates the calculation and results of a wind group coincidence analysis for ten-minute and one-minute data, under the four *aggregate* wind penetration scenarios (the 1310 MW level is not considered "aggregate" because it is a single group of existing/signed projects).

Table 5.23 One-Minute and Ten-Minute Wind Group Coincident Analyses for Various Output Levels

1-Min Data (180 hrs)

	Aggregate Wind Max -ve Delta	Aggregate Wind Max +ve Delta	Group Wind Coincident Max -ve Delta	Group Wind Coincident Max +ve Delta	Coincidence Factor Max -ve Delta	Coincidence Factor Max +ve Delta
5000 MW	-79	112	-215	241	**0.37**	**0.46**
6000 MW	-118	101	-274	309	**0.43**	**0.33**
8000 MW	-128	116	-338	372	**0.38**	**0.31**
10000 MW	-155	139	-338	372	**0.46**	**0.37**
				AVG:	**0.41**	**0.37**

10-Min Data (1 year)

	Aggregate Wind Max -ve Delta	Aggregate Wind Max +ve Delta	Group Wind Coincident Max -ve Delta	Group Wind Coincident Max +ve Delta	Coincidence Factor Max -ve Delta	Coincidence Factor Max +ve Delta
5000 MW	-704	998	-2394	2795	**0.29**	**0.36**
6000 MW	-1080	934	-3232	3793	**0.33**	**0.25**
8000 MW	-1130	1040	-3948	4484	**0.29**	**0.23**
10000 MW	-1359	1333	-3948	4484	**0.34**	**0.30**
				AVG:	**0.31**	**0.28**

The calculation procedure is quite straightforward. From the aggregate wind series for each scenario (5000 MW, 6000 MW, 8000 MW, 10,000 MW), the maximum negative and positive changes in wind output were computed (based on natural diversity). This is the data recorded in column 2 (Aggregate Wind Max –ve Delta) and column 3 (Aggregate Wind Max +ve Delta) of Table 5.23. These are analogous to non-coincident peaks.

For each of the ten wind groups and the group of existing/signed projects, the maximum negative delta and maximum positive delta were computed. Assuming that each of these individual group maximum changes occurred simultaneously, the maximum *coincident* change in aggregate wind output was computed for each wind scenario. This is the data recorded in column 4 (Group Wind Coincident Max -ve Delta) and column 5 (Group Wind Coincident Max +ve Delta) of Table 5.23. These are analogous to coincident peaks.

The coincidence factors for wind drops and wind rises are computed by taking the ratio of the non-coincident peaks to the coincident peaks. This is the data recorded in column 6 (Coincidence Factor Max -ve Delta) and column 7 (Coincidence Factor Max +ve Delta) of Table 5.23.

The coincidence factors can be interpreted as the fraction of the maximum possible (coincident) change in a group wind output that shows up in the actual aggregate wind output. The bottom line: when sudden changes in wind output occur, wind group diversity significantly reduces the impact of any single change on the aggregate output --- by as much as 60% across 1 minute and 70% across 10 minutes. This argument can be extrapolated to the wind sites that make up the wind groups (see Table 5.22). Certainly, as the analysis becomes more granular (i.e. site level as opposed to of group level), there is likely to be more diverse behavior and less coincidence among wind sites. One would expect the site-to-site correlation to be even less than the group-to-group correlation, and by extension, the wind site coincidence factors should be smaller. This means that a smaller portion of individual site extreme changes would tend show up in the aggregate wind output.

The next subsection addresses the contribution of extreme weather incidents to *sudden* reductions in wind output.

5.6.3 Extreme Weather Incidents

Extremes of weather incidents such as high operating temperatures, windstorms or icing events associated with the Great Lakes may force wind plant shutdown either due to the high level of wind, absence of wind, or structural damage. These events are outside the scope of “normal operation” and may sometimes even exceed the design limit of the infrastructure. As a result, the key question is not whether or not wind generation will be available during extreme weather incidents, but rather how quickly or suddenly the wind generation will abate during these events. To address this question, the physical characteristics of Ontario must be considered, as well as the characteristics of extreme weather events. The latter is best revealed by a study of historical weather patterns and incidents in Ontario and the Northeast.

Ontario is the second largest (and most populous) province in Canada, with an area of 1,076,395 square kilometers, representing 10% of the national land area. The vast size of Ontario and the proximity to large bodies of water has a tremendous impact on the climate and weather variations within the province.

As shown in Figure 5.35, Ontario is bounded on the north by Hudson Bay and James Bay, and the American border which is mostly water, passes through four of the five Great Lakes, Superior, Huron (which includes Georgian Bay), Erie, and Ontario.

Figure 5.35 Location of the Province of Ontario within Canada

The Great Lakes region in the south of the province has the majority of the population, and is also the region where the wind groups in this study are located. An expansion of this region was shown earlier in Figure 5.34, along with the location of the wind groups. In the figure, the distance between group 2 on the northern shore of Lake Superior and group 8 on the shore of Lake Erie is approximately 1000 km. This extensive distance between the groups is a primary contributor to the low wind correlation between the two locations. In general, due to the vast size of Ontario, temperatures, and weather conditions may vary tremendously from region to region and even within the regions themselves. The following is a succinct description of the climate of Ontario from Environment Canada.[7]

Ontario's climate varies widely from season to season and from one part of the province to another. In Northern Ontario, the climate is primarily continental, with cold winters and mild summers. Most precipitation falls in the form of summer showers and thunderstorms; winter snowfall amounts can be impressive, but usually contain less water. Precipitation amounts increase as one moves from northwest to southeast - a reflection of the increasing influence of moisture transported from the Great Lakes and the Gulf of Mexico. In Southern Ontario, the climate is highly modified by the influence of the Great Lakes. The addition of moisture from the Great Lakes in autumn and winter increases precipitation amounts, while the heat of the Great Lakes protects the region from the worst of winter's cold.

Ontario experiences a variety of extreme weather events. In winter, Northern Ontario can have prolonged periods of extreme cold. Farther south, very heavy snow is a regular feature in the snowbelts to the lee of Lakes Superior and Huron, and Georgian Bay; major storms lash most parts of Ontario at least once or twice per year, with high

[7] Environment Canada, *The Canada Country Study: Climate Impacts and Adaptation*, http://www.on.ec.gc.ca/canada-country-study/intro.html

winds and a mix of rain, freezing rain and snow. In spring, rapid snowmelt or ice jamming can lead to flooding of Ontario's rivers. Spring also marks the beginning of the tornado season in Southern Ontario, which has the highest frequency of tornadoes in Canada. In summer, thunderstorms can produce heavy downpours, hail, damaging winds and occasional tornadoes. Stagnant tropical air masses can bring poor air quality, heat waves and drought. In autumn, an early frost can damage crops, and remnants of hurricanes occasionally produce high winds and excessive rainfalls.

As the excerpt confirms, two of the major concerns for wind tower structural integrity, high wind and icing, are frequent occurrences in Ontario. However, wind storms in the form of hurricanes or tornadoes, and ice storms that are capable of severely damaging or toppling a wind structure move at finite speeds and are not capable of "*sudden*" wholesale damage to structures across Ontario within "ten minutes or less". To illustrate this point Figure 5.36 shows the tracks of the ice storms that ravaged the Northeastern U.S. and Ontario in January of 1998, taken from a study by the Government of Canada, Office of Critical Infrastructure Protection and Emergency Preparedness.[8]

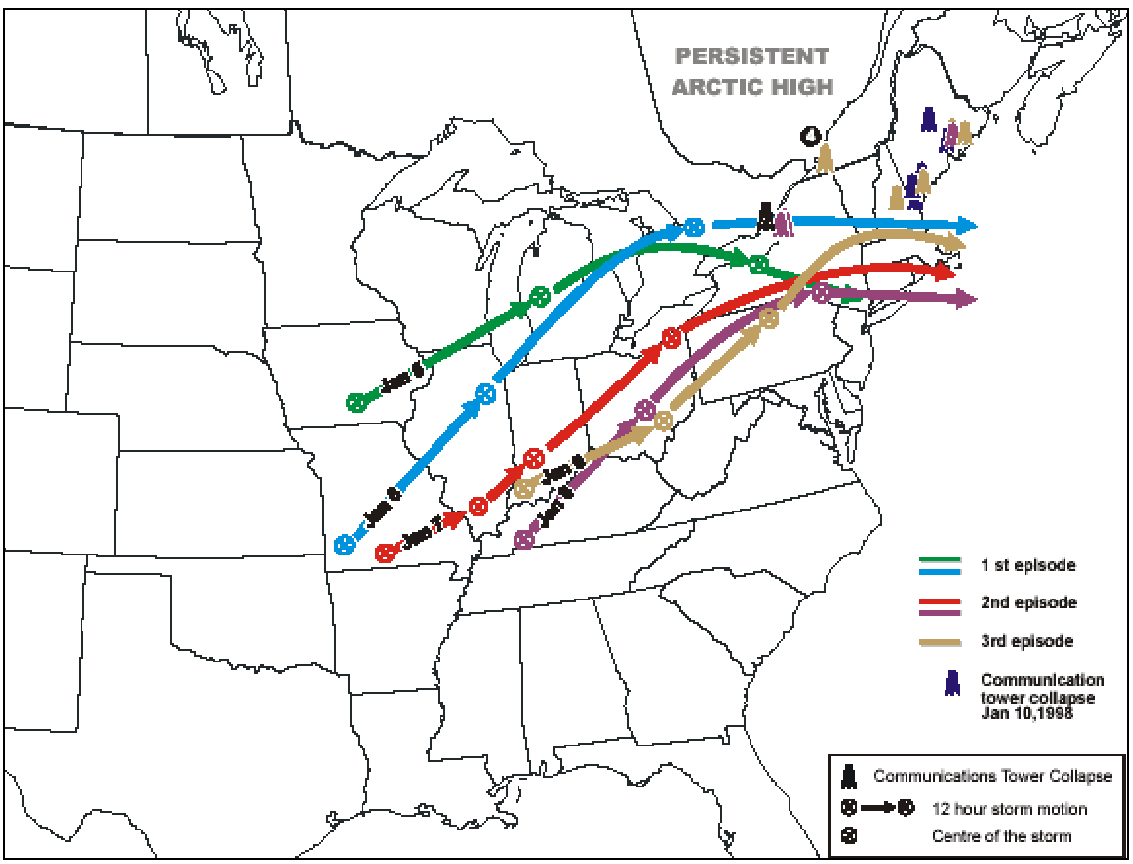


Figure 5.36 Tracks of Storm Systems During January 98 Great Northeast Ice Storm

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8 *Estimation of Severe Ice Storm Risks for South-Central Canada*, Office of Critical Infrastructure Protection and Emergency Preparedness, Government of Canada, 2003, http://ww3.psepc.gc.ca/research/resactivites/natHaz/EC-MSC_2002D002_ENG_CD.pdf

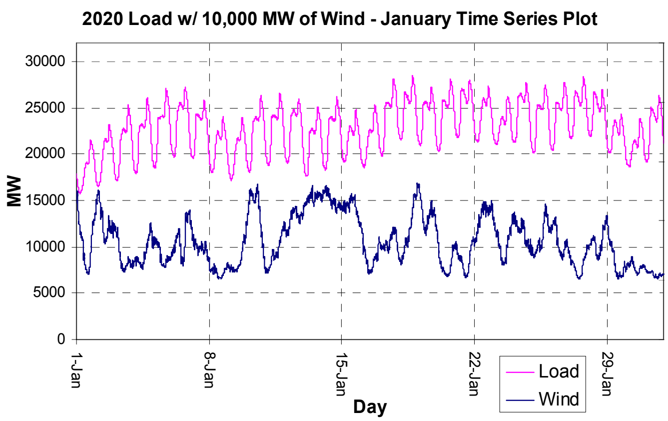
The figure shows the position of the center of the storm systems at twelve-hour intervals. A quick comparison of the storm speed and the size of Ontario shows that the storms would have taken approximately six hours to cross Southern Ontario. The spatial diversity of the wind groups (some are up to 1000 km apart) would virtually ensure that they are not all impacted by the storm at the same time. The same conclusion can be drawn for other storm systems such as hurricanes and tornadoes. Wind group diversity, due to the vast area over which the sites are scattered will virtually guarantee that the aggregate wind will not disappear in ten-minutes or less due to inclement weather.

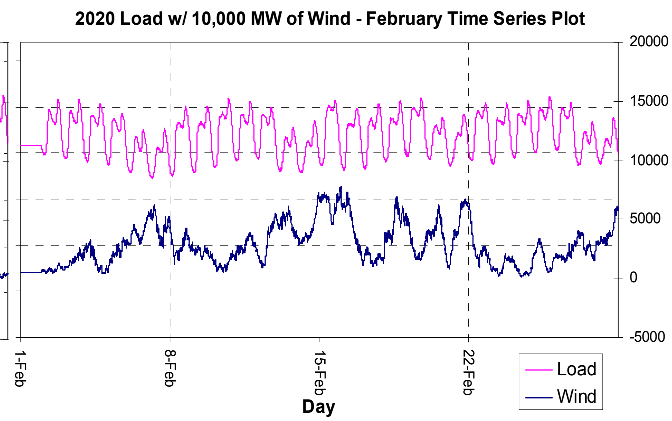
Of course, this does not rule out the possibility that a system moving across Ontario could eventually shutdown all the wind plants in its path. However, this is outside the scope of this discussion, because such an event will probably also compromise the transmission and distribution system. Figure 5.36 shows that the 1998 ice storm was severe enough to topple a communication tower in Ontario. The Government of Canada study notes "communication towers are normally the last structures to fail in an ice storm, and are therefore indicative of the most severe ice storms." It may be reasonable to assume that a storm capable of toppling a communication tower may also topple wind towers and transmission towers, in addition to widespread damage to lines and distribution poles. The point, however, remains that such storms are forecasted and tracked with enough lead time and accuracy that the would not have a *sudden* wholesale impact on *aggregate* wind generation across a land mass as large as Ontario.

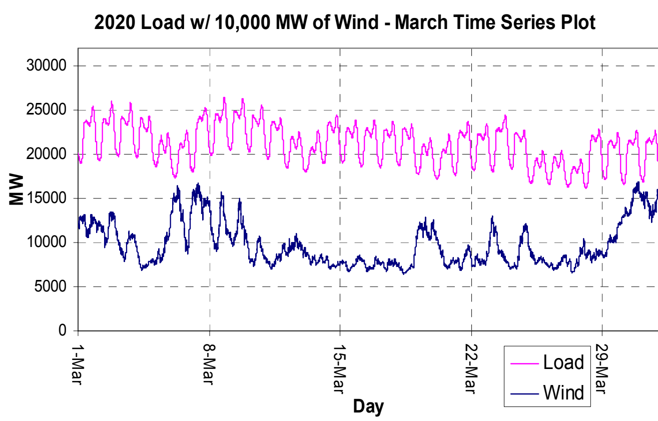
6 Appendix A – Additional Plots

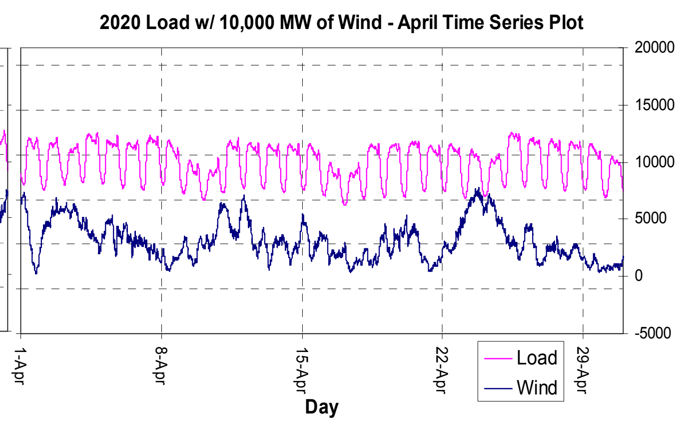
6.1 Monthly Time Series Plots

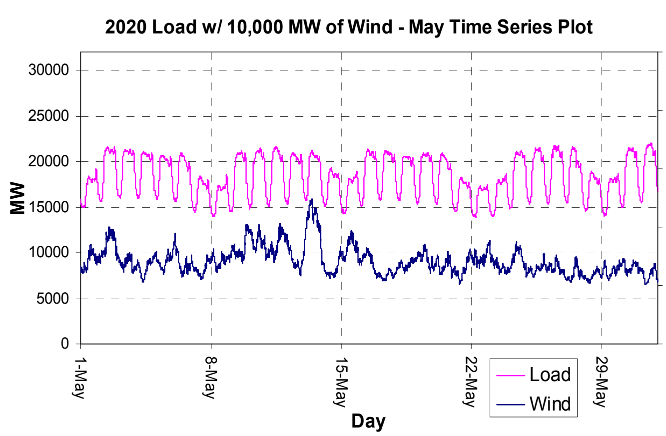
Time series plots for year 2020 load with 10,000 MW of wind for each month of the year are shown below. The left axis (0 to 32,000) is load and the right axis (-5000 to 20,000) is wind. One axis label has been removed from each plot for display purposes.

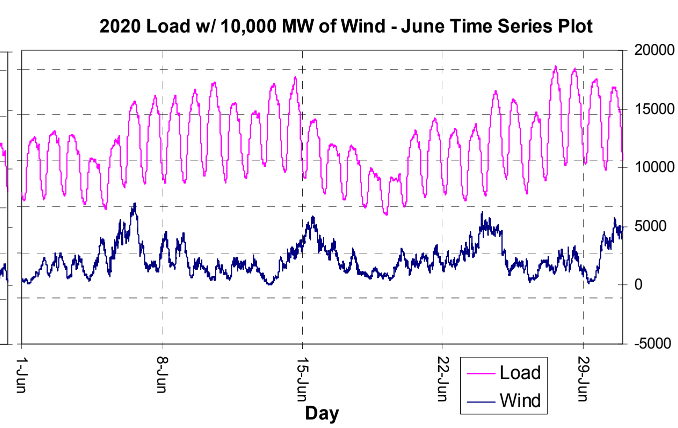




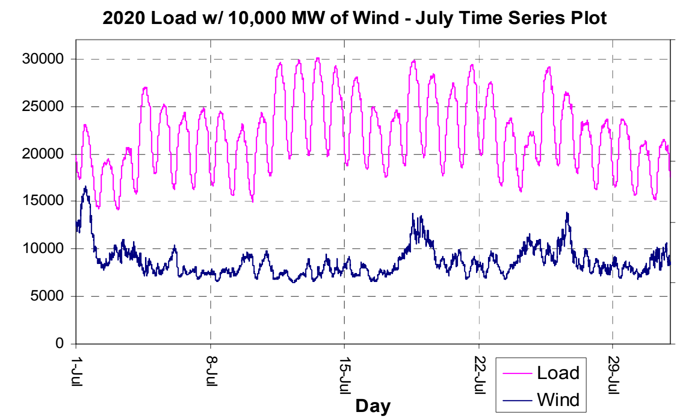


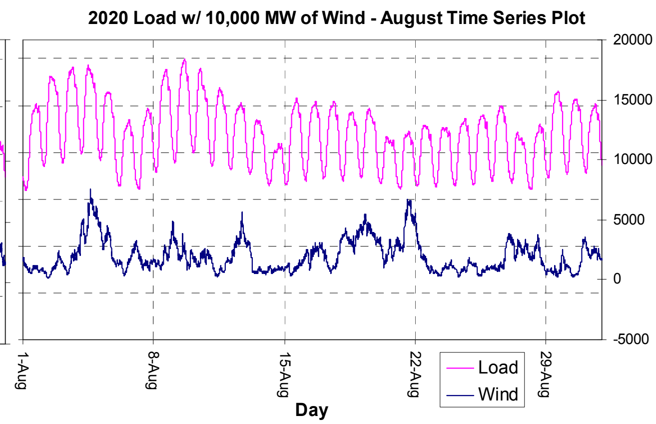


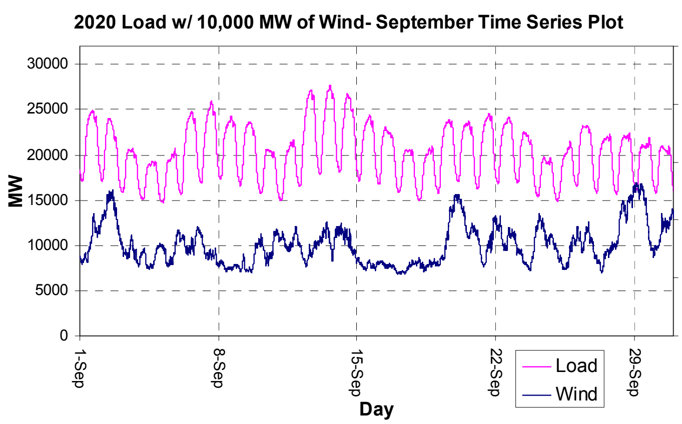


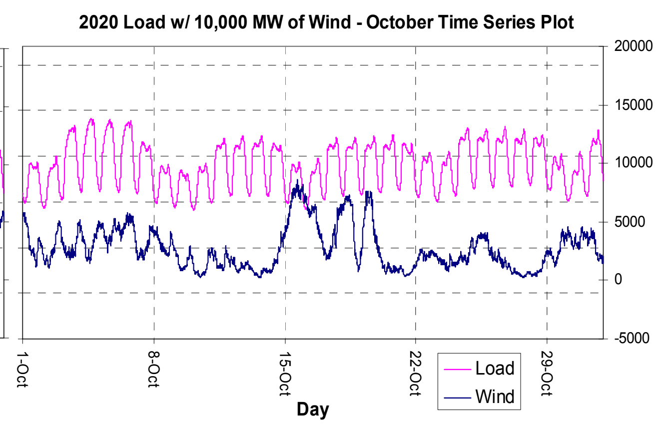


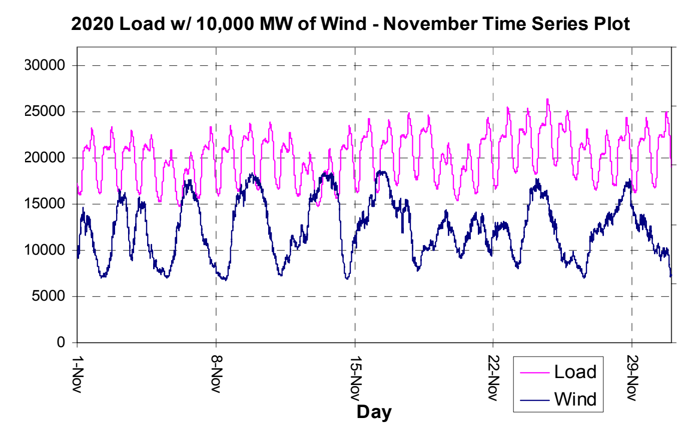
Appendix A – Additional Plots

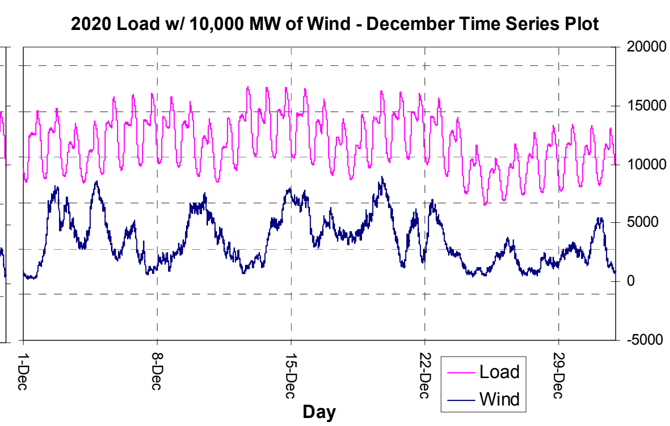




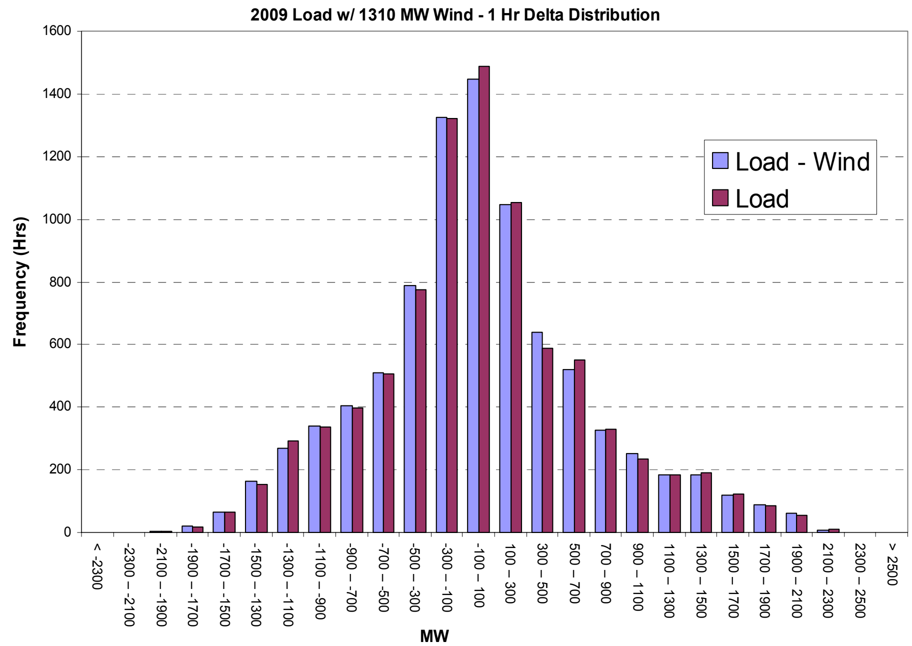


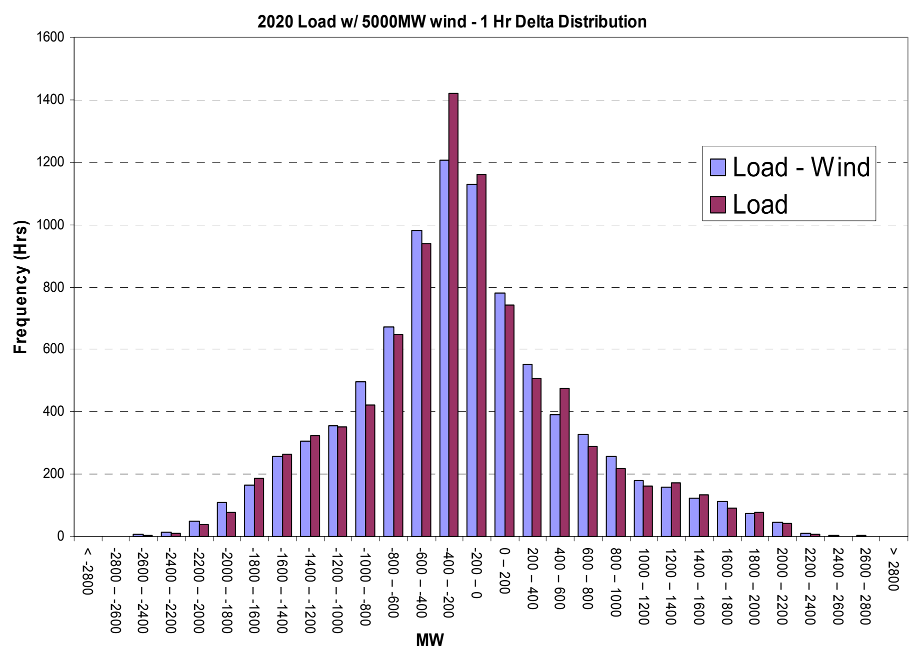


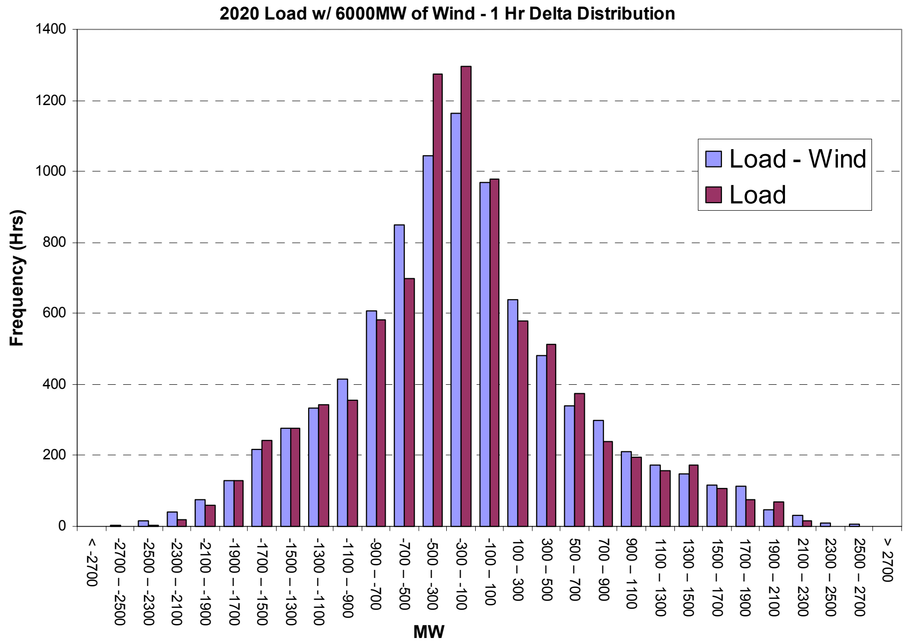


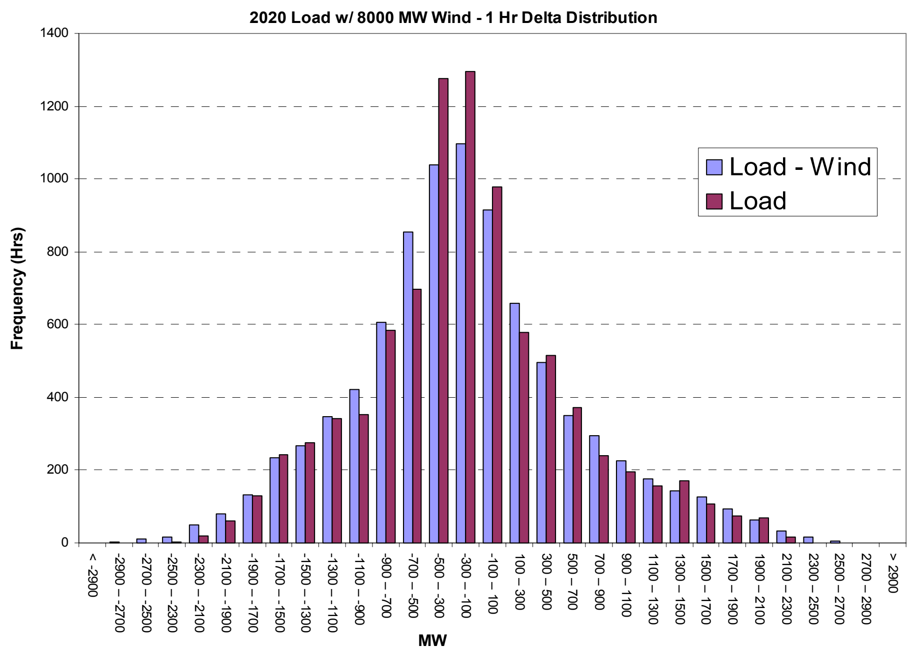


6.2 Distribution of Hourly Load-Wind Deltas

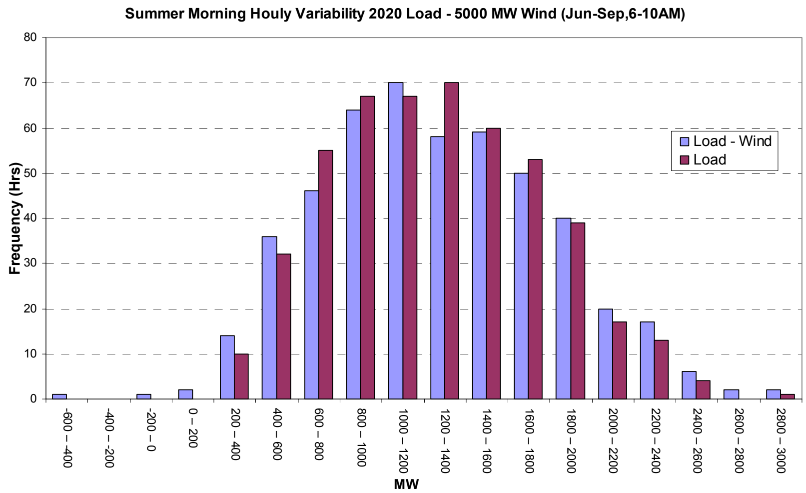


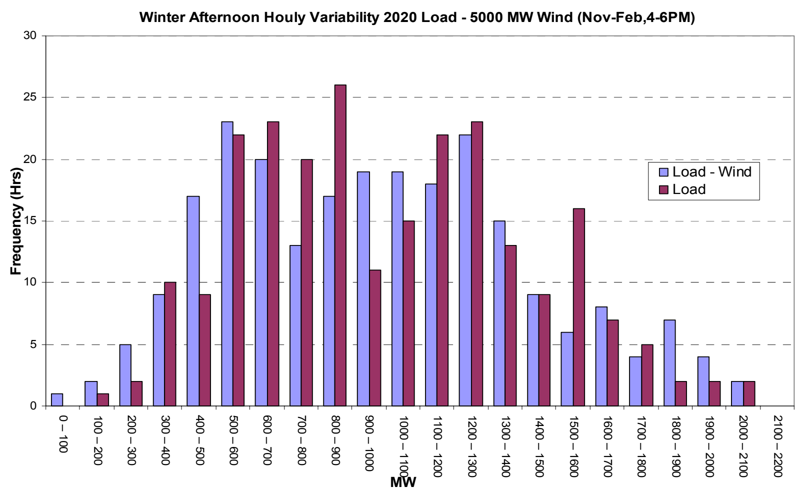


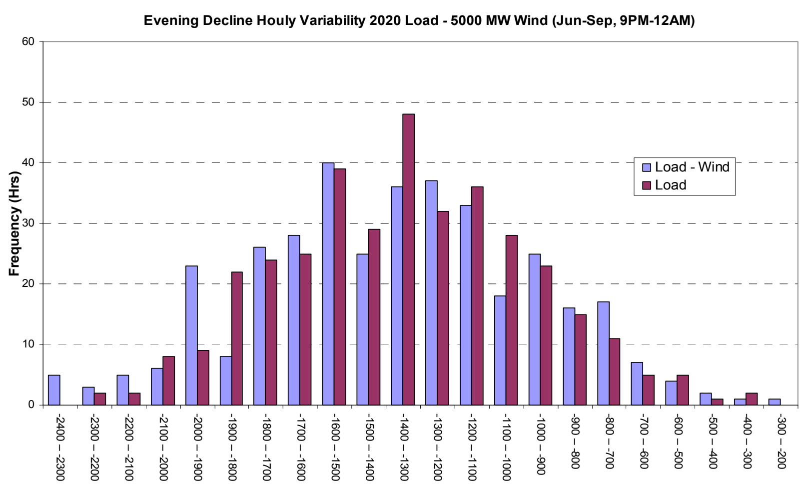

2020 Load w/ 6000MW of Wind - 1 Hr Delta Distribution
Frequency (Hrs)
MW
Load - Wind
Load

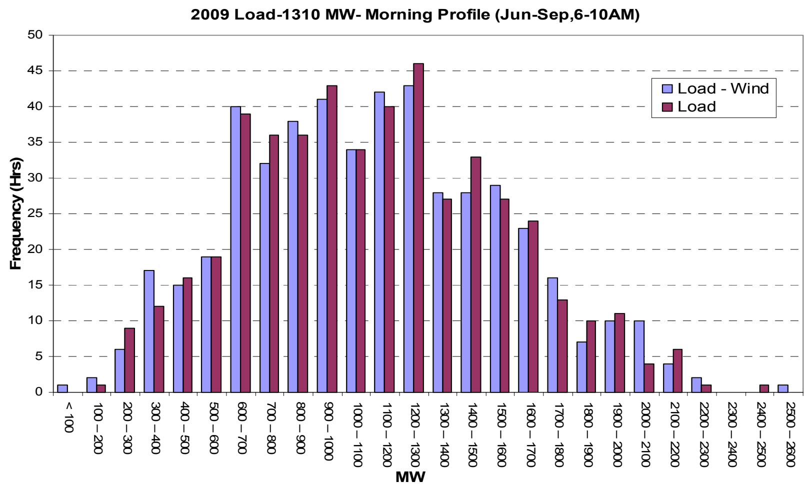

2020 Load w/ 8000 MW Wind - 1 Hr Delta Distribution
Frequency (Hrs)
MW
Load - Wind
Load

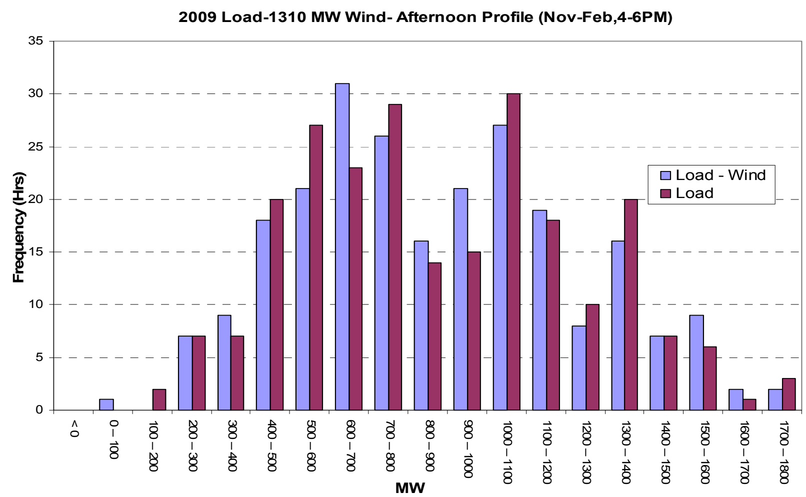
6.3 Morning Rise, Afternoon Rise, Evening Decline Plots

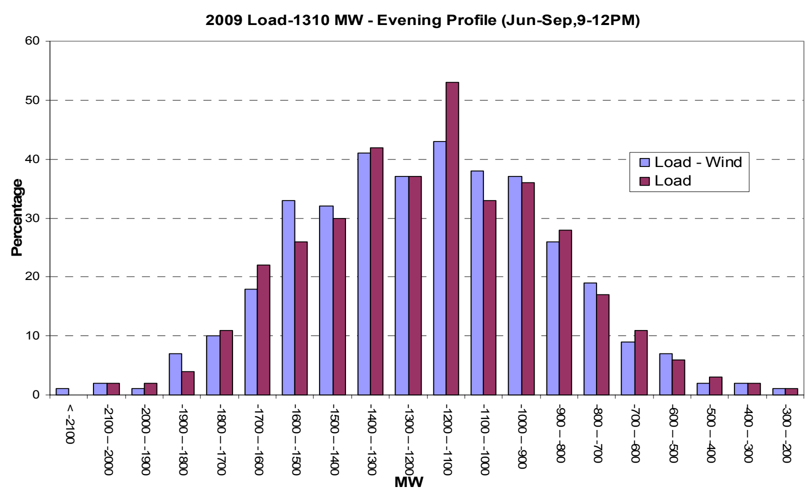




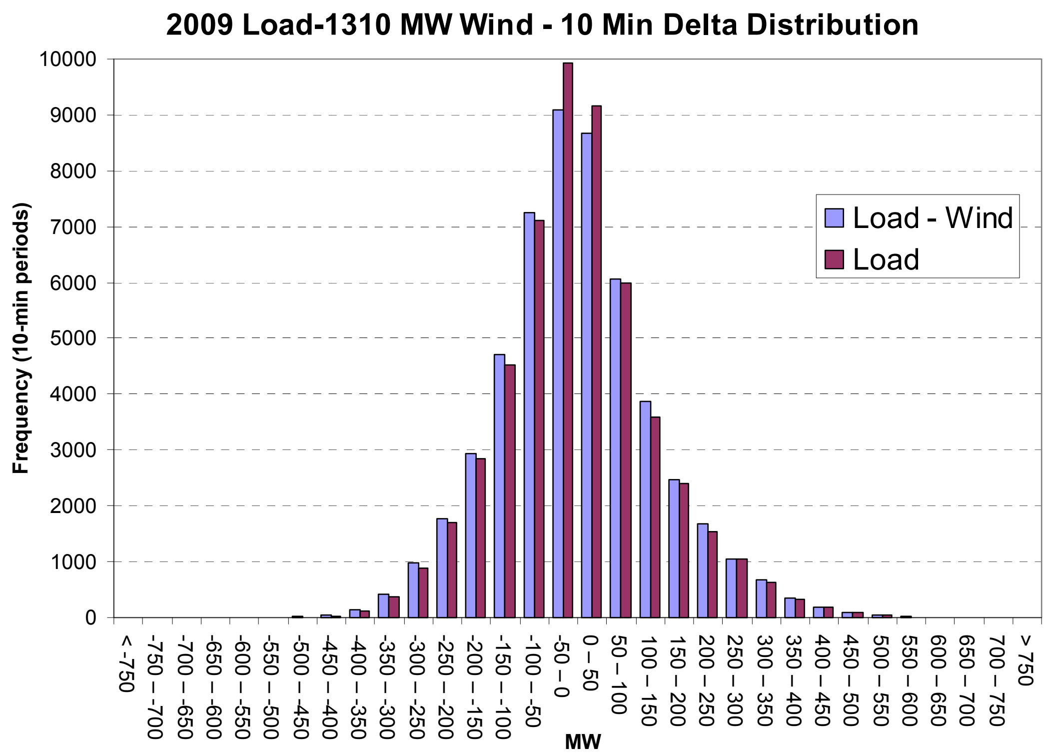


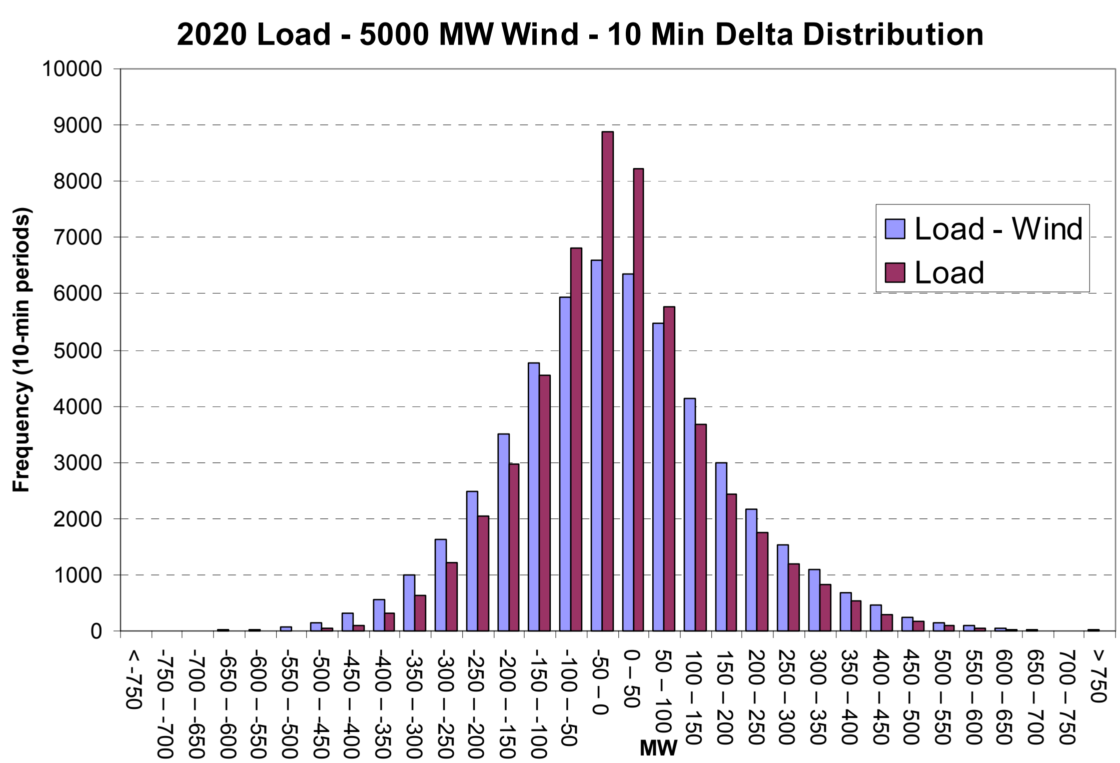

2009 Load-1310 MW- Morning Profile (Jun-Sep,6-10AM)
Frequency (Hrs)
MW
Load - Wind
Load

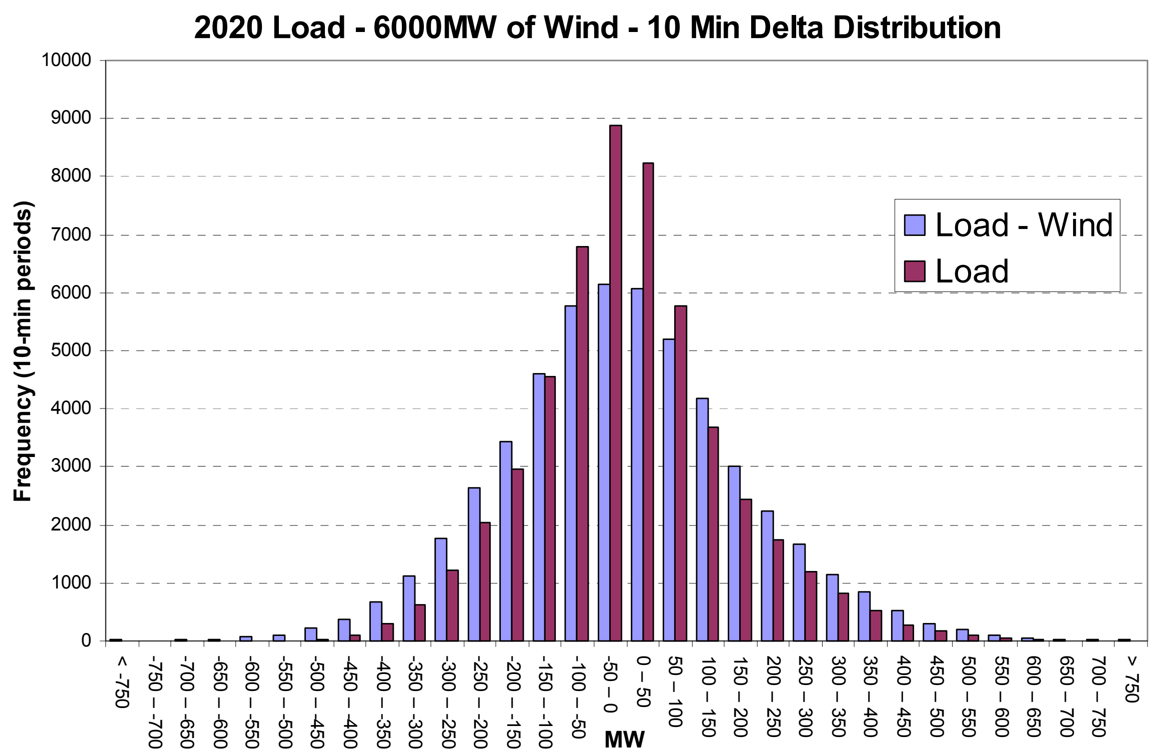

2009 Load-1310 MW Wind- Afternoon Profile (Nov-Feb,4-6PM)
Frequency (Hrs)
MW
Load - Wind
Load

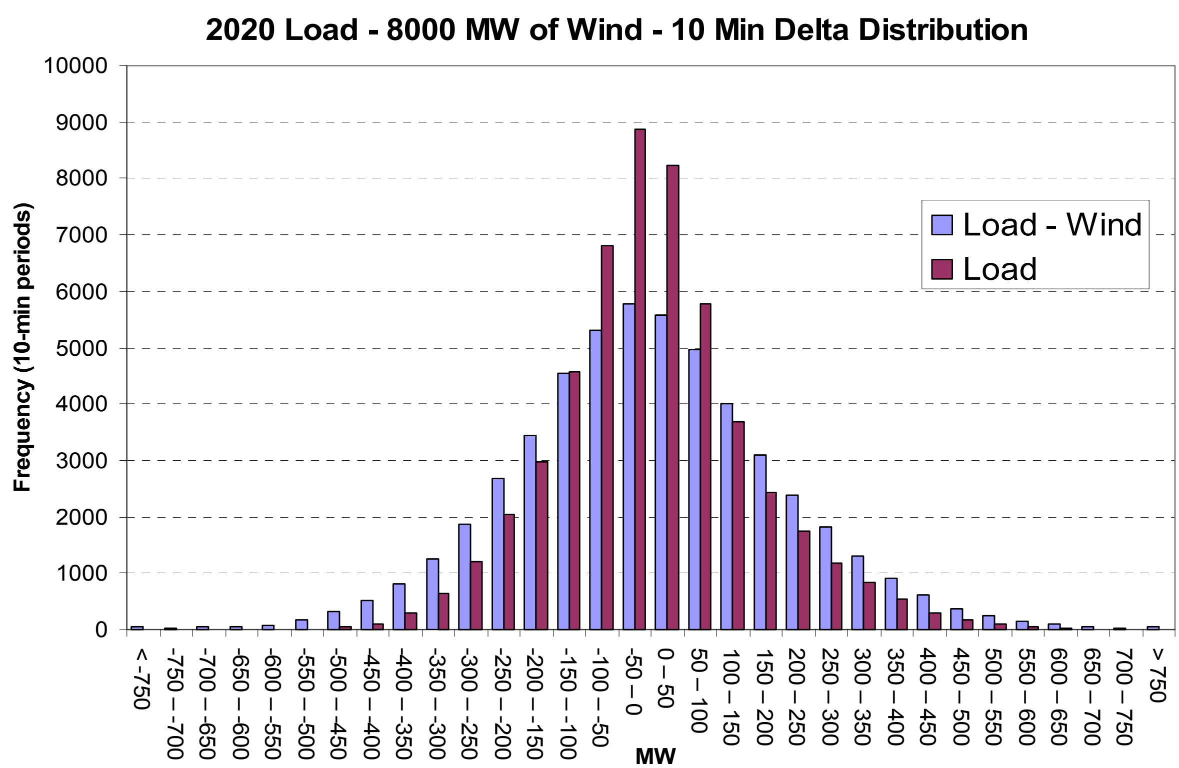

2009 Load-1310 MW - Evening Profile (Jun-Sep,9-12PM)
Percentage
MW
Load - Wind
Load

6.4 Distribution of Ten Minute Load-Wind Deltas






2020 Load - 6000MW of Wind - 10 Min Delta Distribution
Frequency (10-min periods)
MW
Load - Wind
Load


2020 Load - 8000 MW of Wind - 10 Min Delta Distribution
Frequency (10-min periods)
MW
Load - Wind
Load

7 Appendix B – Load and Wind Scenarios

7.1 Load and Wind Data

As discussed in Chapter 3, the load and wind profiles used to develop the scenarios for this study are based upon temporally synchronized load and wind data from 2005. Wind data from 2005 was used because it was the dataset with the fewest gaps to be filled by AWS Truewind. This section describes the data and methods used for deriving the set of future scenarios shown in Figure 7.1.

The source load data provided by the requesting parties was 1-minute time series data for the full 2005 year. As shown in Figure 7.1, this data was the used to derive the 1-minute 2009 and 2020 load values by escalating the 2005 data based upon the latest IESO seasonal normal weather peak load forecast. In other words, the profile or diurnal pattern of the load is assumed to remain the same for the 2009 and 2020 load cases (as stipulated by the requesting parties), but the peak yearly load value is increased according to the IESO forecast. The ratio used to project the 2009 one-minute load data is 1.026 and for the 2020 one-minute load data the scaling factor is 1.162. As an illustration, the 2020 load calculation is shown below:

$$2020 LoadValue = 2005 LoadValue \cdot \frac{2020 PeakForecast}{2005 PeakLoad}$$

Where,

$$\frac{2020 PeakForecast}{2005 PeakLoad} = 1.162$$

The impact of the wind variability on the overall system variability (including load) is coupled to the ratio: wind nameplate value/peak system load. This ratio is also known as the wind penetration level. Assuming that the wind is more variable than the load, then as this ratio increases, so does the overall system variability. In recognition of this fact and to yield *conservative* results, the ratios used to derive the 2009 and 2020 load data were chosen to be the average ratios between the summer and winter peak forecasts, not the highest peak forecast.

In order to analyze the overall system variability for timeframes other than one-minute, the time series data was "integrated" or averaged to calculate data for longer time periods. For example, there are 1,440 one-minute data points in a single day. To obtain the ten-minute data for a single day, the first ten minutes of the load for the day were averaged to produce a ten-minute load value and then the next ten-minutes were averaged and so on. The result is a set of 144 ten-minute data points that is used to assess the ten-minute statistical variability. The same method is used to calculate load data for the five-minute and one-hour time periods used throughout this study. This method of calculating time series data was compared to other methods such as moving averages and sampling of data. The differences in overall analysis results were negligible for these smaller time periods. Time series sampling of data was used for the 3-hour period because the difference between integrating and sampling data was found to be more significant than for the other time periods under consideration.

The ten-minute wind production data provided by AWS Truewind was used to derive the wind production profiles for the five wind scenarios under consideration. Each of the wind scenarios was built up according to Table 8.1.

Table 8.1 Wind Scenario Construction

Wind Nameplate Value	Groups Used
1,310 MW	Signed/Planned/Existing
5,000 MW	Signed + scaled Groups 4 to 10
6,000 MW	Signed + scaled Groups 3 to 10
8,000 MW	Signed + scaled Groups 1 to 10
10,000 MW	Signed + scaled Groups 1 to 10

The scenarios were constructed to represent the expected wind development across the province of Ontario as outlined in the Helimax report. [9] The wind data for each of the groups were scaled to arrive at a production profile that was representative of the associated nameplate value of wind.

Wind production data for the one-hour time period were derived from the ten-minute data yearly data by integrating the ten-minute data. Wind production data for the three-hour time period was derived from the ten-minute data yearly data by sampling the one-hour data and shifting the start time to arrive at the worst-case variability. Each method of calculating production data was compared to alternative methods to ensure that results are worst case.

The ten-minute wind production data were analyzed to identify the extreme periods for which one-minute wind data is required for further analysis. The one-minute data is used to assess the incremental regulation and load following requirements. 180 of the most variable and extreme hours of the year were selected (see Section 5.5) for higher resolution data. The one-minute data provided by AWS Truewind was sampled to derive the 5-minute wind production data.

[9] "*Analysis of Future Wind Farm Development in Ontario*," Helimax Energy, Inc., March 2006

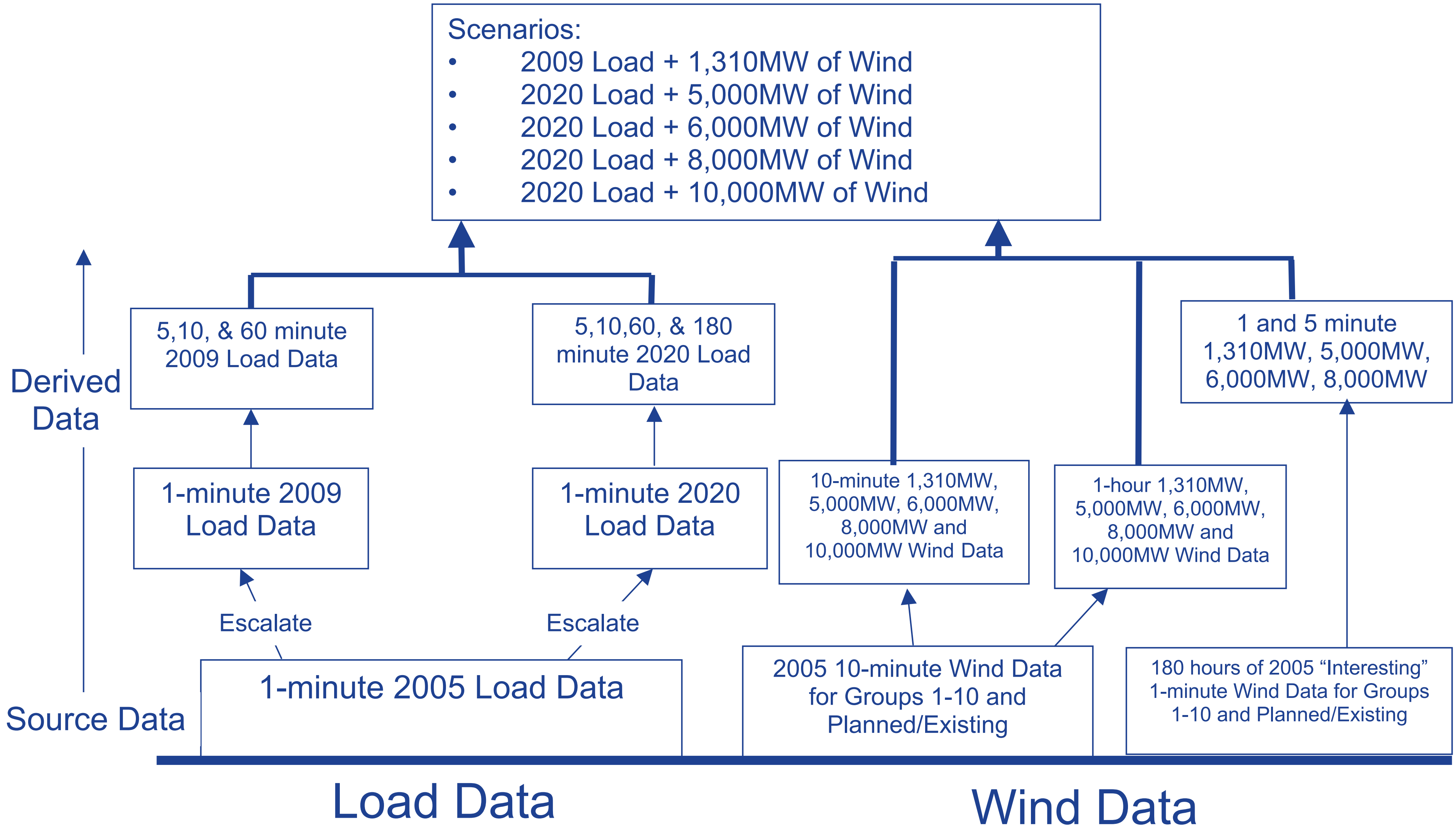


Figure 7.1 The Study Data Foundation

8 Appendix C – Additional Analysis

8.1 Moving Window Analysis

Since the five-minute wind data is obtained by sampling the one-minute data at five-minute intervals, this creates the possibility for large five-minute changes in wind to be overlooked if a particular data point is not selected for the sample. By extension, this could impact the maximum change in combined load and wind and conceivably the overall standard deviation.

A moving window analysis is the most effective method to capture all possible five-minute changes. This is completely analogous to picking another point beside the first as the initial sample and sampling every fifth point thereafter. This procedure will create four additional five-minute wind series all with a different starting point than the original. These are designated as 1-shift, 2-shift, 3-shift, and 4-shift, to differentiate them from the original series (analyzed section 5.5.2), which is designated as 0-shift or no-shift. To maintain synchronism, the 5-minute average load window is also shifted. Figure 8.1 illustrates the procedure for the 0-shift and 1-shift series.

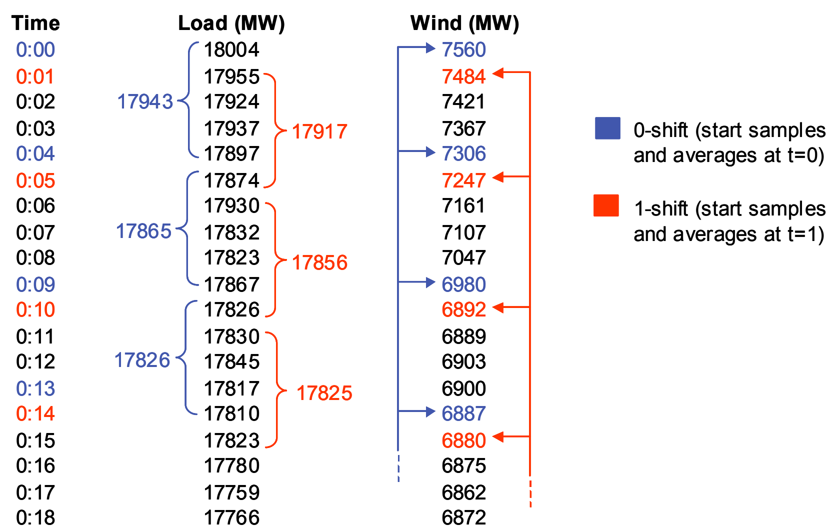


Figure 8.1 Illustration of Sampling and Averaging with Five-Minute Moving Window

A moving window analysis was performed on the five-minute data using the year 2020 load with 10,000 MW of wind scenario to assess the impact of shifting the starting point on the 5-minute variability. Table 8.1 shows the result of this analysis.

The standard deviation of load-wind varies from a low of 149 for the 3-shift case to a high of 161 for the no-shift case. The maximum five-minute rise (750 MW) was highest for the 1-shift case, but only 2.5% higher than the no-shift case. Similarly, the maximum five-minute drop (2507 MW) was also highest for the 1-shift case, but only 2.9% higher than the no-shift case. From a variability (σ) point-of-view, the no-shift (0-shift) case appears to be the most conservative estimate, even though the extreme variations are a little less than some other cases.

Table 8.1 Results Summary of Moving Window (Shifting) Analysis for 2020 Load with 10,000 MW Wind

	Load		Wind		Load-Wind	
0-shift	Mean:	**19**	Mean:	**-1**	Mean:	**19**
	STD:	**110**	STD:	**112**	STD:	**161**
	Min:	**-2221**	Min:	**-716**	Min:	**-2435**
	Max:	**575**	Max:	**629**	Max:	**732**
1-shift	Mean:	**19**	Mean:	**-1**	Mean:	**19**
	STD:	**110**	STD:	**103**	STD:	**156**
	Min:	**-2274**	Min:	**-635**	Min:	**-2507**
	Max:	**638**	Max:	**614**	Max:	**750**
2shift	Mean:	**19**	Mean:	**-1**	Mean:	**19**
	STD:	**106**	STD:	**99**	STD:	**150**
	Min:	**-1645**	Min:	**-650**	Min:	**-1873**
	Max:	**640**	Max:	**618**	Max:	**712**
3-shift	Mean:	**19**	Mean:	**-1**	Mean:	**19**
	STD:	**105**	STD:	**99**	STD:	**149**
	Min:	**-1246**	Min:	**-689**	Min:	**-1454**
	Max:	**584**	Max:	**624**	Max:	**696**
4-shift	Mean:	**19**	Mean:	**-1**	Mean:	**20**
	STD:	**106**	STD:	**103**	STD:	**153**
	Min:	**-1743**	Min:	**-678**	Min:	**-1949**
	Max:	**562**	Max:	**640**	Max:	**701**

For this reason, the no-shift case was chosen as the basis for presentation and observation in this study. Alternative approaches would be to chose the most conservative results from all the cases and use these to assess operation impact, or to use the average results from all the cases. However, the authors believe that working the most conservative of the "shift-cases" is the most consistent approach, the most defensible and certainly the least confusing of the options.

A similar exercise was carried out for the multi-hour analysis, shifting the starting point for the three-hour deltas by 1 and 2 hours. The results showed that the variability of the 1-shift and 2-shift cases were not significantly different than the no-shift case and therefore were not used in further analysis.

8.2 Complete results of Individual Analysis of the 24 Periods

Table 8.2 Individual Analysis of 24 Periods - 2009 Load with 1,310 of Wind

	Start Date/Time	End Date/Time	Length (Hrs)		Load				Wind				Load-Wind				
Large Delta Load Periods					Mean	Max	Min	STD	Mean	Max	Min	STD	Mean	Max	Min	STD	3STDDelta
	6/9/05 3:00 AM	6/9/05 9:00 AM	6	1-Minute	17	135	-82	40	0	7	-8	3	17	135	-83	40	1
				5-Minute	84	266	-47	73	-1	18	-22	9	85	264	-49	74	3
	6/14/05 3:00 PM	6/14/05 9:00 PM	6	1-Minute	17	131	-125	37	0	40	-23	10	17	129	-144	39	4
				5-Minute	87	287	-148	83	-1	187	-85	49	88	328	-139	100	51
	7/18/05 3:00 AM	7/18/05 9:00 AM	6	1-Minute	20	133	-134	40	1	12	-8	4	19	131	-137	40	1
				5-Minute	102	326	-100	82	4	39	-29	16	98	328	-118	84	5
	5/26/05 4:00 AM	5/26/05 7:00 AM	3	1-Minute	22	504	-87	63	0	5	-7	2	23	501	-83	63	0
				5-Minute	106	508	-151	135	-3	17	-24	11	108	496	-154	136	4
	5/27/05 2:00 PM	5/27/05 5:00 PM	3	1-Minute	-6	134	-1469	133	-1	23	-21	8	-5	126	-1473	134	1
				5-Minute	-27	445	-1962	349	-2	97	-91	37	-25	422	-1988	354	15
	6/29/05 7:00 PM	6/29/05 10:00 PM	3	1-Minute	-12	66	-125	35	1	7	-4	2	-13	67	-129	35	0
				5-Minute	-61	100	-215	85	5	21	-8	7	-66	102	-223	86	4
	11/29/05 5:00 AM	11/29/05 8:00 AM	3	1-Minute	23	120	-144	46	0	20	-13	7	23	125	-146	47	3
				5-Minute	122	346	-103	97	2	68	-33	27	121	366	-86	106	27
Large Delta Wind Periods																	
	1/1/05 12:00 AM	1/2/05 12:00 AM	24	1-Minute	0	122	-120	36	0	23	-18	5	0	121	-122	36	1
				5-Minute	0	222	-187	59	-2	98	-81	21	2	212	-159	62	10
	1/6/05 3:00 PM	1/6/05 9:00 PM	6	1-Minute	1	116	-134	44	3	34	-10	7	-1	111	-129	44	-1
				5-Minute	6	186	-145	75	13	146	-33	32	-7	135	-155	70	-15
	3/7/05 9:00 PM	3/8/05 3:00 AM	6	1-Minute	-12	103	-149	41	-2	20	-24	7	-10	102	-154	42	1
				5-Minute	-59	142	-288	75	-8	57	-76	30	-51	159	-256	82	20
	11/14/05 3:00 AM	11/14/05 9:00 AM	6	1-Minute	13	118	-80	36	-2	11	-12	4	15	124	-76	36	0
				5-Minute	67	265	-67	73	-11	20	-41	14	78	277	-67	74	2
	7/26/05 11:00 AM	7/26/05 2:00 PM	3	1-Minute	3	686	-695	93	1	28	-21	9	2	675	-708	93	2
				5-Minute	13	159	-135	68	6	79	-73	43	7	148	-157	74	17
	12/2/05 7:00 PM	12/2/05 10:00 PM	3	1-Minute	-11	79	-140	35	-3	9	-40	9	-8	80	-140	36	3
				5-Minute	-54	19	-255	49	-13	33	-185	45	-41	146	-266	68	54
Large Delta Load-Wind Periods																	
	4/20/05 3:00 AM	4/20/05 9:00 AM	6	1-Minute	14	144	-130	38	0	20	-15	6	14	144	-125	39	2
				5-Minute	69	261	-163	76	0	74	-53	30	69	275	-143	82	16
	7/25/05 3:00 AM	7/25/05 9:00 AM	6	1-Minute	18	196	-141	45	0	9	-7	3	19	192	-135	45	-1
				5-Minute	93	331	-87	95	-1	27	-29	12	94	327	-88	91	-11
	7/18/05 8:00 PM	7/18/05 11:00 PM	3	1-Minute	-22	77	-131	36	0	14	-14	5	-22	84	-128	37	3
				5-Minute	-110	35	-195	61	-1	51	-56	26	-109	59	-201	75	42
	12/5/05 4:00 AM	12/5/05 7:00 AM	3	1-Minute	17	153	-140	41	-1	15	-18	6	18	147	-146	41	2
				5-Minute	85	296	-84	75	-4	32	-64	27	90	314	-84	81	18
Low Load Periods with High Delta Load-Wind																	
	4/12/05 9:00 AM	4/12/05 3:00 PM	6	1-Minute	-1	374	-197	40	-1	14	-14	6	-1	371	-196	40	1
				5-Minute	-8	168	-192	47	-3	54	-55	25	-5	195	-204	56	26
	5/9/05 4:00 PM	5/9/05 10:00 PM	6	1-Minute	-8	107	-195	44	1	9	-9	4	-8	108	-199	44	1
				5-Minute	-37	151	-248	81	5	36	-29	15	-42	138	-260	83	5
	5/22/05 1:00 AM	5/22/05 7:00 AM	6	1-Minute	2	123	-118	34	0	10	-10	4	2	121	-115	35	1
				5-Minute	8	172	-103	50	0	42	-36	17	8	180	-94	54	11
	11/6/05 3:00 AM	11/6/05 3:00 PM	12	1-Minute	4	120	-176	41	1	24	-21	5	4	118	-178	41	0
				5-Minute	22	165	-120	56	3	102	-99	22	19	183	-134	57	5
High Wind Periods with Low Delta Wind																	
	3/30/05 4:00 PM	3/30/05 10:00 PM	6	1-Minute	-1	125	-98	36	0	20	-16	6	-1	133	-105	36	1
				5-Minute	-4	217	-183	69	-1	74	-71	27	-3	228	-208	72	8
	11/12/05 9:00 PM	11/13/05 9:00 PM	24	1-Minute	0	112	-132	34	0	17	-14	4	0	111	-133	34	1
				5-Minute	1	176	-198	64	0	76	-53	14	2	175	-199	66	4
	11/15/05 9:00 AM	11/16/05 9:00 AM	24	1-Minute	0	311	-160	40	0	22	-22	6	-1	312	-151	41	2
				5-Minute	-2	452	-201	85	2	97	-97	29	-4	450	-224	92	19
		Total Hours =	180	Max(1 min):	23	686	-1469	133	3	40	-40	10	23	675	-1473	134	4
				Max(5 min):	122	508	-1962	349	13	187	-185	49	121	496	-1988	354	54
				|MaxDelta|(1 min) :		1469		|MaxDelta|(1 min) :			40		|MaxDelta|(1 min) :			1473	
				|MaxDelta|(5 min) :		1962		|MaxDelta|(5 min) :			187		|MaxDelta|(5 min) :			1988	

Table 8.3 Individual Analysis of 24 Periods - 2020 Load with 5,000 of Wind

	Start Date/Time	End Date/Time	Length (Hrs)		Load				Wind				Load-Wind				
Large Delta Load Periods					Mean	Max	Min	STD	Mean	Max	Min	STD	Mean	Max	Min	STD	3STDDelta
	6/9/05 3:00 AM	6/9/05 9:00 AM	6	1-Minute	19	153	-93	45	-1	19	-17	7	20	153	-91	46	3
				5-Minute	95	301	-54	82	-7	47	-72	26	103	314	-78	93	32
	6/14/05 3:00 PM	6/14/05 9:00 PM	6	1-Minute	20	149	-142	42	1	112	-45	23	19	165	-163	49	20
				5-Minute	99	325	-167	94	3	515	-179	116	96	450	-331	154	181
	7/18/05 3:00 AM	7/18/05 9:00 AM	6	1-Minute	23	151	-152	45	2	28	-23	8	21	157	-161	47	5
				5-Minute	115	369	-114	93	10	108	-98	37	105	401	-132	107	41
	5/26/05 4:00 AM	5/26/05 7:00 AM	3	1-Minute	25	571	-99	72	-1	11	-11	5	26	567	-98	72	1
				5-Minute	120	575	-171	153	-4	33	-40	19	124	549	-169	155	7
	5/27/05 2:00 PM	5/27/05 5:00 PM	3	1-Minute	-7	152	-1663	151	-5	46	-40	18	-2	134	-1675	153	8
				5-Minute	-31	504	-2221	395	-20	211	-172	87	-11	545	-2294	419	71
	6/29/05 7:00 PM	6/29/05 10:00 PM	3	1-Minute	-14	74	-142	40	1	15	-13	6	-15	83	-138	40	0
				5-Minute	-69	114	-243	96	5	54	-40	26	-73	129	-244	101	15
	11/29/05 5:00 AM	11/29/05 8:00 AM	3	1-Minute	26	136	-163	52	-5	39	-43	14	32	157	-169	54	6
				5-Minute	139	391	-117	110	-25	125	-150	61	164	432	-62	123	39
Large Delta Wind Periods																	
	1/1/05 12:00 AM	1/2/05 12:00 AM	24	1-Minute	0	138	-136	40	-1	49	-46	14	2	137	-158	43	8
				5-Minute	0	251	-211	67	-8	211	-207	64	8	291	-221	97	90
	1/6/05 3:00 PM	1/6/05 9:00 PM	6	1-Minute	1	131	-152	50	7	63	-55	19	-6	114	-168	51	4
				5-Minute	7	211	-165	85	35	290	-221	90	-28	166	-361	112	80
	3/7/05 9:00 PM	3/8/05 3:00 AM	6	1-Minute	-13	116	-168	47	-6	42	-57	16	-8	130	-179	50	11
				5-Minute	-66	161	-327	85	-28	123	-225	73	-39	211	-284	118	98
	11/14/05 3:00 AM	11/14/05 9:00 AM	6	1-Minute	15	134	-91	41	-8	16	-48	12	23	182	-81	43	4
				5-Minute	76	300	-76	83	-37	70	-181	53	114	381	-94	99	49
	7/26/05 11:00 AM	7/26/05 2:00 PM	3	1-Minute	3	776	-787	105	1	69	-48	21	2	748	-814	107	7
				5-Minute	14	180	-153	77	7	290	-209	102	7	241	-310	119	126
	12/2/05 7:00 PM	12/2/05 10:00 PM	3	1-Minute	-12	89	-158	40	-8	38	-79	22	-4	118	-162	44	12
				5-Minute	-61	21	-289	56	-41	146	-363	107	-20	318	-289	117	183
Large Delta Load-Wind Periods																	
	4/20/05 3:00 AM	4/20/05 9:00 AM	6	1-Minute	16	163	-148	43	1	51	-39	16	14	190	-152	45	8
				5-Minute	78	295	-185	87	8	219	-172	77	71	418	-226	121	102
	7/25/05 3:00 AM	7/25/05 9:00 AM	6	1-Minute	21	222	-159	51	-1	20	-21	8	22	217	-141	51	0
				5-Minute	105	375	-98	107	-6	67	-83	33	111	392	-99	110	10
	7/18/05 8:00 PM	7/18/05 11:00 PM	3	1-Minute	-25	87	-149	41	0	30	-30	13	-25	87	-158	43	8
				5-Minute	-125	39	-221	69	-3	128	-117	63	-122	67	-270	99	90
	12/5/05 4:00 AM	12/5/05 7:00 AM	3	1-Minute	20	173	-158	46	-2	31	-46	15	22	182	-172	49	11
				5-Minute	97	335	-95	84	-12	86	-192	68	109	344	-127	113	86
Low Load Periods with High Delta Load-Wind																	
	4/12/05 9:00 AM	4/12/05 3:00 PM	6	1-Minute	-2	423	-223	45	-1	35	-27	12	-1	422	-217	47	5
				5-Minute	-9	191	-218	54	-3	128	-118	55	-6	281	-206	81	81
	5/9/05 4:00 PM	5/9/05 10:00 PM	6	1-Minute	-9	121	-221	50	4	30	-27	11	-12	120	-223	50	1
				5-Minute	-42	171	-280	92	20	126	-100	46	-62	130	-286	94	5
	5/22/05 1:00 AM	5/22/05 7:00 AM	6	1-Minute	2	139	-134	39	-1	27	-21	9	3	141	-127	40	4
				5-Minute	9	195	-117	57	-7	90	-81	38	16	183	-154	71	43
	11/6/05 3:00 AM	11/6/05 3:00 PM	12	1-Minute	5	136	-199	47	1	51	-39	13	4	158	-238	48	5
				5-Minute	25	186	-136	63	7	190	-167	63	18	228	-240	85	66
High Wind Periods with Low Delta Wind																	
	3/30/05 4:00 PM	3/30/05 10:00 PM	6	1-Minute	-1	142	-110	41	1	51	-38	16	-2	131	-123	43	7
				5-Minute	-4	245	-208	78	4	213	-140	72	-9	297	-282	106	84
	11/12/05 9:00 PM	11/13/05 9:00 PM	24	1-Minute	0	127	-150	39	0	42	-35	10	0	118	-158	40	4
				5-Minute	2	199	-224	73	2	167	-144	44	-1	275	-293	84	34
	11/15/05 9:00 AM	11/16/05 9:00 AM	24	1-Minute	0	352	-181	46	1	52	-35	13	-2	353	-174	47	5
				5-Minute	-2	512	-227	97	7	226	-131	58	-8	509	-280	112	47
		Total Hours =	**180**	**Max(1 min):**	**26**	**776**	**-1663**	**151**	**7**	**112**	**-79**	**23**	**32**	**748**	**-1675**	**153**	**20**
				Max(5 min):	**139**	**575**	**-2221**	**395**	**35**	**515**	**-363**	**116**	**164**	**549**	**-2294**	**419**	**183**
				|MaxDelta|(1 min) :		**1663**			**|MaxDelta|(1 min) :**		**112**		**|MaxDelta|(1 min) :**			**1675**	
				|MaxDelta|(5 min) :		**2221**			**|MaxDelta|(5 min) :**		**515**		**|MaxDelta|(5 min) :**			**2294**	

Table 8.4 Individual Analysis of 24 Periods - 2020 Load with 6,000 of Wind

	Start Date/Time	End Date/Time	Length (Hrs)		Load				Wind				Load-Wind				
Large Delta Load Periods					**Mean**	**Max**	**Min**	**STD**	**Mean**	**Max**	**Min**	**STD**	**Mean**	**Max**	**Min**	**STD**	**3STDDelta**
	6/9/05 3:00 AM	6/9/05 9:00 AM	6	1-Minute	19	153	-93	45	-3	21	-32	10	22	150	-95	47	6
				5-Minute	95	301	-54	82	-16	72	-123	44	111	354	-76	102	59
	6/14/05 3:00 PM	6/14/05 9:00 PM	6	1-Minute	20	149	-142	42	1	103	-45	23	18	167	-174	49	20
				5-Minute	99	325	-167	94	7	472	-171	114	92	438	-310	153	177
	7/18/05 3:00 AM	7/18/05 9:00 AM	6	1-Minute	23	151	-152	45	2	32	-28	11	21	161	-161	48	7
				5-Minute	115	369	-114	93	11	145	-98	53	104	391	-155	115	66
	5/26/05 4:00 AM	5/26/05 7:00 AM	3	1-Minute	25	571	-99	72	0	15	-9	5	26	570	-98	72	1
				5-Minute	120	575	-171	153	-2	51	-34	19	122	559	-179	155	8
	5/27/05 2:00 PM	5/27/05 5:00 PM	3	1-Minute	-7	152	-1663	151	-4	50	-48	23	-3	134	-1698	156	15
				5-Minute	-31	504	-2221	395	-14	236	-213	109	-17	549	-2371	436	122
	6/29/05 7:00 PM	6/29/05 10:00 PM	3	1-Minute	-14	74	-142	40	5	27	-13	7	-19	76	-139	40	1
				5-Minute	-69	114	-243	96	24	84	-38	29	-92	70	-308	96	1
	11/29/05 5:00 AM	11/29/05 8:00 AM	3	1-Minute	26	136	-163	52	-4	44	-54	20	31	164	-183	57	14
				5-Minute	139	391	-117	110	-18	168	-217	95	157	609	-120	156	138
Large Delta Wind Periods																	
	1/1/05 12:00 AM	1/2/05 12:00 AM	24	1-Minute	0	138	-136	40	-1	54	-53	14	1	138	-157	43	8
				5-Minute	0	251	-211	67	-6	246	-203	66	6	251	-253	98	93
	1/6/05 3:00 PM	1/6/05 9:00 PM	6	1-Minute	1	131	-152	50	8	73	-49	19	-6	118	-175	51	5
				5-Minute	7	211	-165	85	38	316	-204	91	-31	160	-394	117	95
	3/7/05 9:00 PM	3/8/05 3:00 AM	6	1-Minute	-13	116	-168	47	-6	39	-54	16	-7	124	-167	51	11
				5-Minute	-66	161	-327	85	-30	118	-190	72	-36	211	-261	117	95
	11/14/05 3:00 AM	11/14/05 9:00 AM	6	1-Minute	15	134	-91	41	-10	19	-43	11	24	176	-79	43	5
				5-Minute	76	300	-76	83	-47	45	-155	46	123	363	-54	99	49
	7/26/05 11:00 AM	7/26/05 2:00 PM	3	1-Minute	3	776	-787	105	6	82	-44	25	-3	716	-844	107	8
				5-Minute	14	180	-153	77	35	343	-177	126	-20	212	-380	129	156
	12/2/05 7:00 PM	12/2/05 10:00 PM	3	1-Minute	-12	89	-158	40	-13	39	-121	30	1	154	-159	49	26
				5-Minute	-61	21	-289	56	-64	168	-555	150	2	511	-255	158	306
Large Delta Load-Wind Periods																	
	4/20/05 3:00 AM	4/20/05 9:00 AM	6	1-Minute	16	163	-148	43	0	49	-49	18	16	195	-148	47	12
				5-Minute	78	295	-185	87	-1	207	-221	88	80	458	-234	136	149
	7/25/05 3:00 AM	7/25/05 9:00 AM	6	1-Minute	21	222	-159	51	-2	23	-19	7	23	223	-146	51	1
				5-Minute	105	375	-98	107	-10	76	-75	31	115	378	-146	115	25
	7/18/05 8:00 PM	7/18/05 11:00 PM	3	1-Minute	-25	87	-149	41	-3	36	-43	18	-22	107	-162	47	18
				5-Minute	-125	39	-221	69	-20	151	-175	87	-105	203	-300	135	199
	12/5/05 4:00 AM	12/5/05 7:00 AM	3	1-Minute	20	173	-158	46	-4	38	-56	19	24	192	-166	51	15
				5-Minute	97	335	-95	84	-22	111	-245	92	118	357	-141	132	143
Low Load Periods with High Delta Load-Wind																	
	4/12/05 9:00 AM	4/12/05 3:00 PM	6	1-Minute	-2	423	-223	45	-4	33	-43	17	2	431	-210	49	11
				5-Minute	-9	191	-218	54	-18	128	-178	82	9	324	-220	105	155
	5/9/05 4:00 PM	5/9/05 10:00 PM	6	1-Minute	-9	121	-221	50	5	47	-30	14	-13	128	-205	51	3
				5-Minute	-42	171	-280	92	23	215	-121	66	-64	108	-386	104	35
	5/22/05 1:00 AM	5/22/05 7:00 AM	6	1-Minute	2	139	-134	39	-1	45	-46	15	3	140	-146	42	11
				5-Minute	9	195	-117	57	-2	183	-175	69	11	241	-247	97	120
	11/6/05 3:00 AM	11/6/05 3:00 PM	12	1-Minute	5	136	-199	47	3	45	-42	14	2	158	-232	49	6
				5-Minute	25	186	-136	63	15	179	-182	68	10	261	-220	86	71
High Wind Periods with Low Delta Wind																	
	3/30/05 4:00 PM	3/30/05 10:00 PM	6	1-Minute	-1	142	-110	41	1	47	-36	14	-2	136	-127	43	6
				5-Minute	-4	245	-208	78	4	191	-127	66	-8	289	-279	102	71
	11/12/05 9:00 PM	11/13/05 9:00 PM	24	1-Minute	0	127	-150	39	0	43	-37	11	0	119	-156	40	5
				5-Minute	2	199	-224	73	2	154	-146	49	-1	345	-272	87	42
	11/15/05 9:00 AM	11/16/05 9:00 AM	24	1-Minute	0	352	-181	46	2	79	-48	17	-2	355	-182	49	9
				5-Minute	-2	512	-227	97	10	327	-208	80	-11	495	-408	124	83
		Total Hours =	**180**	**Max(1 min):**	**26**	**776**	**-1663**	**151**	**8**	**103**	**-121**	**30**	**31**	**716**	**-1698**	**156**	**26**
				Max(5 min):	**139**	**575**	**-2221**	**395**	**38**	**472**	**-555**	**150**	**157**	**609**	**-2371**	**436**	**306**
				|MaxDelta|(1 min) :		**1663**		**|MaxDelta|(1 min) :**			**121**		**|MaxDelta|(1 min) :**			**1698**	
				|MaxDelta|(5 min) :		**2221**		**|MaxDelta|(5 min) :**			**555**		**|MaxDelta|(5 min) :**			**2371**	

Table 8.5 Individual Analysis of 24 Periods - 2020 Load with 8,000 of Wind

	Start Date/Time	End Date/Time	Length (Hrs)		Load				Wind				Load-Wind				
Large Delta Load Periods					**Mean**	**Max**	**Min**	**STD**	**Mean**	**Max**	**Min**	**STD**	**Mean**	**Max**	**Min**	**STD**	**3STDDelta**
	6/9/05 3:00 AM	6/9/05 9:00 AM	6	1-Minute	19	153	-93	45	-5	22	-41	12	24	152	-90	48	7
				5-Minute	95	301	-54	82	-24	68	-152	53	120	362	-79	105	69
	6/14/05 3:00 PM	6/14/05 9:00 PM	6	1-Minute	20	149	-142	42	3	116	-45	26	17	167	-180	50	24
				5-Minute	99	325	-167	94	13	527	-185	127	86	449	-352	163	208
	7/18/05 3:00 AM	7/18/05 9:00 AM	6	1-Minute	23	151	-152	45	2	38	-32	12	20	162	-159	48	8
				5-Minute	115	369	-114	93	11	143	-100	56	103	400	-151	114	62
	5/26/05 4:00 AM	5/26/05 7:00 AM	3	1-Minute	25	571	-99	72	2	25	-22	10	24	571	-100	73	2
				5-Minute	120	575	-171	153	8	90	-64	42	112	535	-160	160	22
	5/27/05 2:00 PM	5/27/05 5:00 PM	3	1-Minute	-7	152	-1663	151	-4	53	-50	24	-2	136	-1702	157	18
				5-Minute	-31	504	-2221	395	-17	245	-219	118	-14	554	-2391	441	139
	6/29/05 7:00 PM	6/29/05 10:00 PM	3	1-Minute	-14	74	-142	40	9	49	-15	11	-23	71	-143	42	5
				5-Minute	-69	114	-243	96	45	165	-45	51	-113	89	-306	113	50
	11/29/05 5:00 AM	11/29/05 8:00 AM	3	1-Minute	26	136	-163	52	-3	51	-63	24	30	173	-170	59	20
				5-Minute	139	391	-117	110	-15	216	-241	117	154	632	-133	173	189
Large Delta Wind Periods																	
	1/1/05 12:00 AM	1/2/05 12:00 AM	24	1-Minute	0	138	-136	40	-1	58	-70	18	1	141	-157	44	11
				5-Minute	0	251	-211	67	-6	263	-280	84	6	277	-270	108	124
	1/6/05 3:00 PM	1/6/05 9:00 PM	6	1-Minute	1	131	-152	50	9	79	-49	21	-8	120	-177	52	7
				5-Minute	7	211	-165	85	45	360	-202	100	-38	158	-443	123	113
	3/7/05 9:00 PM	3/8/05 3:00 AM	6	1-Minute	-13	116	-168	47	-7	47	-68	20	-6	127	-173	52	16
				5-Minute	-66	161	-327	85	-35	132	-248	90	-31	295	-284	131	137
	11/14/05 3:00 AM	11/14/05 9:00 AM	6	1-Minute	15	134	-91	41	-11	20	-52	13	26	185	-78	44	8
				5-Minute	76	300	-76	83	-54	53	-180	59	130	386	-87	110	81
	7/26/05 11:00 AM	7/26/05 2:00 PM	3	1-Minute	3	776	-787	105	7	106	-46	29	-4	716	-838	109	12
				5-Minute	14	180	-153	77	36	456	-175	143	-22	207	-485	155	234
	12/2/05 7:00 PM	12/2/05 10:00 PM	3	1-Minute	-12	89	-158	40	-15	47	-128	33	3	165	-162	51	32
				5-Minute	-61	21	-289	56	-72	174	-594	164	11	549	-254	169	340
Large Delta Load-Wind Periods																	
	4/20/05 3:00 AM	4/20/05 9:00 AM	6	1-Minute	16	163	-148	43	-2	46	-83	24	17	227	-141	50	22
				5-Minute	78	295	-185	87	-8	177	-390	118	86	634	-225	167	241
	7/25/05 3:00 AM	7/25/05 9:00 AM	6	1-Minute	21	222	-159	51	-3	30	-35	10	24	217	-151	52	4
				5-Minute	105	375	-98	107	-17	75	-109	43	122	438	-143	126	55
	7/18/05 8:00 PM	7/18/05 11:00 PM	3	1-Minute	-25	87	-149	41	-4	35	-58	21	-21	122	-162	49	25
				5-Minute	-125	39	-221	69	-24	133	-245	99	-101	276	-287	149	239
	12/5/05 4:00 AM	12/5/05 7:00 AM	3	1-Minute	20	173	-158	46	-6	42	-67	22	25	201	-171	53	21
				5-Minute	97	335	-95	84	-27	123	-285	106	124	377	-94	144	178
Low Load Periods with High Delta Load-Wind																	
	4/12/05 9:00 AM	4/12/05 3:00 PM	6	1-Minute	-2	423	-223	45	-5	40	-54	20	4	450	-196	50	14
				5-Minute	-9	191	-218	54	-26	153	-227	96	17	312	-197	113	178
	5/9/05 4:00 PM	5/9/05 10:00 PM	6	1-Minute	-9	121	-221	50	5	52	-44	17	-14	126	-199	51	4
				5-Minute	-42	171	-280	92	28	224	-184	81	-70	175	-384	107	44
	5/22/05 1:00 AM	5/22/05 7:00 AM	6	1-Minute	2	139	-134	39	-1	47	-44	16	3	143	-148	43	13
				5-Minute	9	195	-117	57	-5	189	-151	75	14	246	-240	104	143
	11/6/05 3:00 AM	11/6/05 3:00 PM	12	1-Minute	5	136	-199	47	4	52	-51	17	1	170	-214	50	8
				5-Minute	25	186	-136	63	18	185	-233	79	7	271	-234	94	92
High Wind Periods with Low Delta Wind																	
	3/30/05 4:00 PM	3/30/05 10:00 PM	6	1-Minute	-1	142	-110	41	1	51	-46	17	-2	133	-133	45	11
				5-Minute	-4	245	-208	78	6	211	-148	77	-10	292	-313	119	122
	11/12/05 9:00 PM	11/13/05 9:00 PM	24	1-Minute	0	127	-150	39	1	51	-49	15	-1	133	-162	41	7
				5-Minute	2	199	-224	73	4	209	-213	67	-2	372	-305	96	70
	11/15/05 9:00 AM	11/16/05 9:00 AM	24	1-Minute	0	352	-181	46	2	89	-52	19	-3	352	-180	49	11
				5-Minute	-2	512	-227	97	12	366	-225	87	-14	496	-412	130	99
		Total Hours =	**180**	**Max(1 min):**	**26**	**776**	**-1663**	**151**	**9**	**116**	**-128**	**33**	**30**	**716**	**-1702**	**157**	**32**
				Max(5 min):	**139**	**575**	**-2221**	**395**	**45**	**527**	**-594**	**164**	**154**	**634**	**-2391**	**441**	**340**
				|MaxDelta|(1 min) :		**1663**		**|MaxDelta|(1 min) :**			**128**		**|MaxDelta|(1 min) :**			**1702**	
				|MaxDelta|(5 min) :		**2221**		**|MaxDelta|(5 min) :**			**594**		**|MaxDelta|(5 min) :**			**2391**	

Table 8.6 Individual Analysis of 24 Periods - 2020 Load with 10,000 of Wind

	Start Date/Time	End Date/Time	Length (Hrs)		Load				Wind				Load-Wind				
Large Delta Load Periods					**Mean**	**Max**	**Min**	**STD**	**Mean**	**Max**	**Min**	**STD**	**Mean**	**Max**	**Min**	**STD**	**3STDDelta**
	6/9/05 3:00 AM	6/9/05 9:00 AM	6	1-Minute	19	153	-93	45	-6	27	-54	15	25	157	-94	49	11
				5-Minute	95	301	-54	82	-31	90	-199	68	127	383	-96	116	83
	6/14/05 3:00 PM	6/14/05 9:00 PM	6	1-Minute	20	149	-142	42	4	139	-57	31	16	173	-186	53	33
				5-Minute	99	325	-167	94	17	629	-237	153	81	473	-447	185	212
	7/18/05 3:00 AM	7/18/05 9:00 AM	6	1-Minute	23	151	-152	45	3	46	-42	16	20	166	-160	49	12
				5-Minute	115	369	-114	93	14	177	-127	72	101	409	-163	124	76
	5/26/05 4:00 AM	5/26/05 7:00 AM	3	1-Minute	25	571	-99	72	2	31	-28	12	23	571	-101	73	4
				5-Minute	120	575	-171	153	11	116	-78	53	108	527	-156	164	17
	5/27/05 2:00 PM	5/27/05 5:00 PM	3	1-Minute	-7	152	-1663	151	-5	63	-65	30	-1	141	-1713	159	24
				5-Minute	-31	504	-2221	395	-22	289	-268	146	-9	577	-2435	457	182
	6/29/05 7:00 PM	6/29/05 10:00 PM	3	1-Minute	-14	74	-142	40	12	62	-21	15	-26	71	-142	43	8
				5-Minute	-69	114	-243	96	57	211	-63	65	-125	82	-328	121	63
	11/29/05 5:00 AM	11/29/05 8:00 AM	3	1-Minute	26	136	-163	52	-5	63	-81	31	31	182	-172	62	30
				5-Minute	139	391	-117	110	-20	269	-307	149	159	698	-175	199	212
Large Delta Wind Periods																	
	1/1/05 12:00 AM	1/2/05 12:00 AM	24	1-Minute	0	138	-136	40	-1	71	-87	22	1	149	-163	46	17
				5-Minute	0	251	-211	67	-7	312	-355	106	7	328	-324	126	151
	1/6/05 3:00 PM	1/6/05 9:00 PM	6	1-Minute	1	131	-152	50	11	102	-61	26	-10	118	-186	54	12
				5-Minute	7	211	-165	85	55	465	-252	124	-48	163	-548	143	142
	3/7/05 9:00 PM	3/8/05 3:00 AM	6	1-Minute	-13	116	-168	47	-9	60	-87	25	-4	138	-174	55	24
				5-Minute	-66	161	-327	85	-44	165	-318	114	-23	358	-316	150	179
	11/14/05 3:00 AM	11/14/05 9:00 AM	6	1-Minute	15	134	-91	41	-14	25	-65	17	29	199	-82	45	13
				5-Minute	76	300	-76	83	-67	67	-232	76	143	438	-91	122	88
	7/26/05 11:00 AM	7/26/05 2:00 PM	3	1-Minute	3	776	-787	105	8	131	-54	35	-5	702	-849	111	17
				5-Minute	14	180	-153	77	45	570	-205	177	-31	237	-595	186	264
	12/2/05 7:00 PM	12/2/05 10:00 PM	3	1-Minute	-12	89	-158	40	-19	63	-155	42	7	192	-163	56	48
				5-Minute	-61	21	-289	56	-90	238	-716	205	29	672	-295	208	338
Large Delta Load-Wind Periods																	
	4/20/05 3:00 AM	4/20/05 9:00 AM	6	1-Minute	16	163	-148	43	-3	55	-105	31	18	247	-141	54	33
				5-Minute	78	295	-185	87	-10	225	-496	149	89	732	-261	195	285
	7/25/05 3:00 AM	7/25/05 9:00 AM	6	1-Minute	21	222	-159	51	-4	39	-45	13	25	217	-150	53	7
				5-Minute	105	375	-98	107	-22	99	-144	55	127	458	-165	134	65
	7/18/05 8:00 PM	7/18/05 11:00 PM	3	1-Minute	-25	87	-149	41	-5	41	-74	26	-20	138	-167	52	34
				5-Minute	-125	39	-221	69	-30	157	-309	124	-95	340	-318	172	307
	12/5/05 4:00 AM	12/5/05 7:00 AM	3	1-Minute	20	173	-158	46	-7	53	-87	28	27	215	-174	56	31
				5-Minute	97	335	-95	84	-34	157	-352	133	130	444	-112	166	211
Low Load Periods with High Delta Load-Wind																	
	4/12/05 9:00 AM	4/12/05 3:00 PM	6	1-Minute	-2	423	-223	45	-7	53	-67	25	5	459	-188	53	22
				5-Minute	-9	191	-218	54	-33	196	-282	121	24	340	-219	136	192
	5/9/05 4:00 PM	5/9/05 10:00 PM	6	1-Minute	-9	121	-221	50	7	65	-57	22	-15	136	-192	53	8
				5-Minute	-42	171	-280	92	35	280	-237	102	-76	226	-411	119	50
	5/22/05 1:00 AM	5/22/05 7:00 AM	6	1-Minute	2	139	-134	39	-1	59	-55	20	3	144	-153	45	20
				5-Minute	9	195	-117	57	-6	238	-191	96	15	284	-282	123	183
	11/6/05 3:00 AM	11/6/05 3:00 PM	12	1-Minute	5	136	-199	47	4	65	-65	22	1	184	-218	51	13
				5-Minute	25	186	-136	63	22	240	-296	101	3	334	-290	111	117
High Wind Periods with Low Delta Wind																	
	3/30/05 4:00 PM	3/30/05 10:00 PM	6	1-Minute	-1	142	-110	41	2	60	-55	21	-3	128	-138	46	16
				5-Minute	-4	245	-208	78	8	252	-179	95	-12	303	-337	134	138
	11/12/05 9:00 PM	11/13/05 9:00 PM	24	1-Minute	0	127	-150	39	1	67	-66	19	-1	144	-169	43	12
				5-Minute	2	199	-224	73	5	277	-289	86	-4	425	-340	109	86
	11/15/05 9:00 AM	11/16/05 9:00 AM	24	1-Minute	0	352	-181	46	3	116	-64	23	-3	352	-185	51	17
				5-Minute	-2	512	-227	97	15	477	-281	110	-17	492	-504	146	104
		Total Hours =	**180**	**Max(1 min):**	**26**	**776**	**-1663**	**151**	**12**	**139**	**-155**	**42**	**31**	**702**	**-1713**	**159**	**48**
				Max(5 min):	**139**	**575**	**-2221**	**395**	**58**	**619**	**-659**	**168**	**159**	**758**	**-2446**	**456**	**338**
				|MaxDelta|(1 min) :		**1663**		**|MaxDelta|(1 min) :**			**155**		**|MaxDelta|(1 min) :**			**1713**	
				|MaxDelta|(5 min) :		**2221**		**|MaxDelta|(5 min) :**			**659**		**|MaxDelta|(5 min) :**			**2446**	